Prepared for:
United States Department of Energy National Energy Technology Laboratory
Contract No. DE-AC26-99FT40342

Gasification Plant Cost and Performance Optimization
Task 1 Topical Report IGCC Plant Cost Optimization

Volume 1

Submitted By:

BECHTEL

GLOBAL ENERGY

Nexant

MAY 2002

U. S. Department of Energy
National Energy Technology Laboratory (NETL)

Gasification Plant Cost and Performance Optimization (Contract No. DE-AC26-99FT40342)

Task 1 Topical Report
IGCC Plant Cost Optimization

Volume 1 of 3

May 2002

Work Performed from September 1999 to January 2002

Prepared by:

Bechtel Corporation
3000 Post Oak Boulevard
Houston, TX 77056

Global Energy Inc.
Suite 3800
1000 Louisiana Street
Houston, TX 77002

Nexant Inc.
Suite 4100
44 Montgomery Street
San Francisco, CA 94104

DISCLAIMER

Abstract

Nexant and Global Energy Inc. performed this Gasification Optimization Study under Department of Energy contract DE-AC26-99FT40342. The goal of this series of design and estimating efforts was to start from the as-built design and actual operating data from the DOE sponsored Wabash River Coal Gasification Repowering Project and to develop optimized designs for several coal and petroleum coke IGCC power and coproduction projects.

First, the team developed a design for a grass-roots plant equivalent to the Wabash River Coal Gasification Repowering Project to provide a starting point and a detailed mid-year 2000 cost estimate based on the actual as-built plant design and subsequent modifications (Subtask 1.1). This unoptimized plant has a thermal efficiency of 38.3% (HHV) and a mid-year 2000 EPC cost of 1,681 \$/kW.[1]

This design was enlarged and modified to become a Petroleum Coke IGCC Coproduction Plant (Subtask 1.2) that produces hydrogen, industrial grade steam, and fuel gas for an adjacent Gulf Coast petroleum refinery in addition to export power. A structured Value Improving Practices (VIP) approach was applied to reduce costs and improve performance. The base case (Subtask 1.3) Optimized Petroleum Coke IGCC Coproduction Plant increased the power output by 16% and reduced the plant cost by 23%. The study looked at several options for gasifier sparing to enhance availability. Subtask 1.9 produced a detailed report on this availability analyses study. The Subtask 1.3 Next Plant, which retains the preferred spare gasification train approach, only reduced the cost by about 21%, but it has the highest availability (94.6%) and produces power at 30 \$/MW-hr (at a 12% ROI). Thus, such a coke-fueled IGCC coproduction plant could fill a near term niche market. In all cases, the emissions performance of these plants is superior to the Wabash River project.

Subtasks 1.5A and B developed designs for single-train coal and coke-fueled power plants. This side-by-side comparison of these plants, which contain the Subtask 1.3 VIP enhancements, showed their similarity both in design and cost (1,318 \$/kW for the coal plant and 1,260 \$/kW for the coke plant). Therefore, in the near term, a coke IGCC power plant could penetrate the market and provide a foundation for future coal-fueled facilities.

Subtask 1.6 generated a design, cost estimate and economics for a multiple train coal-fueled IGCC powerplant, also based on the Subtask 1.3 cases. The Subtask 1.6 four gasification train plant has a thermal efficiency of 40.6% (HHV) and cost 1,066 \$/kW.

The single-train advanced Subtask 1.4 plant, which uses an advanced “G/H-class” combustion turbine, can have a thermal efficiency of 45.4% (HHV) and a plant cost of 1,096 \$/kW. Multi-train plants will further reduce the cost. Again, all these plants have superior emissions performance.

Subtask 1.7 developed an optimized design for a coal to hydrogen plant. At current natural gas prices, this facility is not competitive with hydrogen produced from natural gas. The preferred scenario is to coproduce hydrogen in a plant similar to Subtask 1.3, as described above.

Subtask 1.8 evaluated the potential merits of warm gas cleanup technology. This study showed that selective catalytic oxidation of hydrogen sulfide (SCOHS) is promising. As gasification technology matures, SCOHS and other improvements identified in this study will lead to further cost reductions and efficiency improvements.

[1] All plant costs mentioned in this report are mid-year 2000 EPC costs which exclude contingency, taxes, licensing fees and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs. These excluded items are included in the subsequent discounted cash flow financial analyses.

Table of Contents

Table of Contents (Continued)

Graphical Materials

Table of Contents (Continued)

Appendices

Executive Summary

This "Gasification Plant Cost and Performance Optimization" project, contract number DE-AC26-99FT40342, examines the current state-of-the-art of coal gasification to provide baseline optimized design cases from which the Department of Energy can measure future progress towards commercialization of gasification processes and achievement of the Vision 21 program goals. This optimization focus or metric was to minimize the cost of electric power produced by IGCC plants primarily by reducing the plant capital cost, increasing the efficiency, increasing the overall system availability, coproducing products, and reducing the operating and maintenance costs.

The Vision 21 concept is the approach being developed by the U. S. Department of Energy to promote energy production from fossil fuels in the 21st century. The objective is to integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. Also, it will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Gasification systems are inherently clean, relatively efficient, and commercially demonstrated for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly. Optimization should allow IGCC to become the preferred low cost power generation option.

Starting from the DOE sponsored Wabash River Coal Gasification Repowering Project (at Terre Haute, Indiana), a design and mid-year 2000 cost were developed for a grass-roots plant equivalent to the Wabash River facility. This case updates the then current Wabash River plant by including all modifications and improvements that were made since the initial startup. The mid-year 2000 cost of the grass-roots plant was developed based on the actual construction cost of the Wabash River facility and subsequent modifications; thereby providing a sound cost basis for the subsequent cases.

Table ES-1 summarizes all these cases. The cases described in this table are planning studies to show some options and applications of the E-GAS™ gasification technology.

Significant reductions were achieved. On a $/kW basis, the cost of the 416 MW advanced Subtask 1.4 single-train IGCC power plant was reduced by 34% compared to the 269 MW Wabash River base case (1,116 $/kW vs. 1,681 $/kW)[2]. The required power selling price for a 12% after tax ROI was reduced by about 41% to 39.8 $/MW-hr using a conservative economic scenario.[3] Further improvements have to potential to reduce the cost to 1,096 $/kW-hr and the power price to 39.0 $/MW-hr, and to increase the thermal efficiency to 45.4% (HHV).

[2] All costs are mid-year 2000 costs. They are presented here to show the relative differences between the cases. Current cost estimates should be developed for any proposed application.
[3] All power costs are current year 2000 power costs which increase at 1.7%/year.

The economics for a current day, multi-train IGCC plant (Subtask 1.6) having a design power output of 1,155 MW are almost as good. It will produce a 12% ROI with a current power selling price of 40.2 \$/MW-hr, and it costs even less at 1,066 \$/kW[1].

An optimized petroleum coke IGCC coproduction plant (Subtask 1.3 Next Plant) located on the U. S. Gulf Coast can dispatch power at 30.0 \$/MW-hr while having a 12% ROI. Such a plant will produce 474 MW of export power, 980,000 lb/hr of 750°F/700 psig steam, and 80 MMscfd of 99.0% hydrogen from 5,417 tpd of dry petroleum coke. Because these plants use a low-value feed and coproduce high value products, they currently are economically attractive, and several projects presently are under development. Furthermore, they provide stable long-term costs for the power, steam and hydrogen that are independent of the volatile price of natural gas.

This study report contains general non-confidential information for each of the study cases, such as basic process information, plant layout schedule, and costs. Interested parties who wish to obtain current, detailed confidential project specific information and explore IGCC further, should contact either Bechtel, Global Energy or Nexant.

The above cost reductions were achieved by application of Value Improving Practices. Value Improving Practices are focused activities aimed at removing non-value adding investment from a project scope. This study utilized the following nine practices.

1. Technology Selection
2. Process Simplification
3. Classes of Plant Quality
4. Value Engineering
5. Availability (Reliability) Modeling
6. Design-to-Capacity
7. Plant Layout Otimization
8. Schedule (Constriction and Procurement) Optimization
9. Operating and Maintenance Savings

Employing Value Improving Practices outside of a specific project removes the limitations of schedule constraints and allows a more thorough examination of the ideas that were generated during the process. The Value Improving Practices team, which consisted of operating and maintenance personnel from the Wabash River plant, Global Energy's gasification experts, and Bechtel's engineers and construction specialists, examined all aspects of the proposed plant and generated almost 300 value engineering ideas. Those that were economically viable were incorporated into the optimized designs. Others that require further research are being developed for future applications which will lead to further cost reductions.

Gasification is viewed as the environmentally superior process for power generation from coal. The Wabash River facility demonstrated the superior environmental performance of gasification in terms of SOx, NOx, and particulate emissions. In a carbon constrained environment, the CO_2 easily can be captured for sequestration or other uses. Even without CO_2 capture, CO_2 emissions are minimized because gasification plants are more efficient. The future Subtask 1.4 plant has a thermal efficiency of 44.5% (HHV) compared to the 35% to 37% thermal efficiencies of conventional coal power plants. Compared to a 36% efficient conventional power plant, the Subtask 1.4 plant will generate 24% less CO_2 because it consumes 24% less coal. As gasification technology matures, further efficiency improvements are expected (approaching 50% on a HHV basis); whereas little, if any, improvement appears likely in conventional combustion power plants.

In the near term, for plants starting up in the 2005-2008 time period, the E-GAS^{TM} technology has been demonstrated and commercialized. Achievement of the installed cost goals through application of the optimization techniques shown in the study should be realized in the first plants built, and they will provide a demonstrated basis for additional projects. Operating cost levels already have been demonstrated to a great extent at Wabash River.

Petroleum coke gasification projects could be the first to enter the marketplace. Several of these have already started development. Wabash River has already demonstrated petroleum coke gasification at a commercial scale. The new plants will demonstrate the integration with petroleum refineries and the necessary reliability required to support refinery operations. New capital cost and operating cost standards will be set. Furthermore, they will support the technology and confirm the economics for the coal fueled IGCC power plants that will follow.

As natural gas and power prices increase and environmental constraints for coal fired generation tighten, coal IGCC should also penetrate the power market. As more coal and coke IGCC plants are built, further improvements can be expected which will lead to additional cost reductions that will make IGCC the preferred option for new base-load power plants.

The gasification plant concepts developed in this study for the Subtask 1.6 1,000 MW coal power plant may be competitive in today's market or in the near future. Other applications will develop as the technology matures. With these tools in hand, the United States can move closer to energy independence based on utilizing our domestic resources of coal and eliminating the export of petroleum coke.

The economics of coal-to-power IGCC facilities may be enhanced by federal and state incentive programs which are aimed at increasing the fuel diversity of our power generation resources. Such programs could speed the wider application of IGCC technologies in new facilities and promote the repowering of older plants. Additional demonstration work may be necessary to convince the financial community of the economic viability of IGCC facilities.

The following developments will be key to the long term commercialization of gasification technologies and integration of this environmentally superior solid fuels technology into the existing mix of power plants.

- Development of the "G/H-class" combustion turbine for syngas applications
- Testing gasifier advancements including slurry feed vaporization in the second stage
- Demonstration of warm gas clean-up technologies (e.g., SCOHS)
- Testing of advanced wet and dry filtration options
- Additional optimization work for the lower rank, sub-bituminous and lignite coals
- Development and implementation of large capacity fuel cells; optimization of the integration of gasification with advanced fuel cell processes
- Further advances in Fischer-Tropsch technology or other gas-to-liquids technologies for the production of liquid transportation fuels from coal
- Develop a lower cost means of producing oxygen such as the ITM ceramic membrane system

In summary, this study shows the potential of IGCC based systems to be competitive with, if not superior to, conventional combustion power plants because of their higher efficiency, superior environmental performance, and competitive cost.

Table ES-1

Task 1 Coal and Coke IGCC Case Summaries

Case	Subtask 1.1	Subtask 1.2	Subtask 1.3				Subtask 1.4	Subtask 1.5		Subtask 1.6	Subtask 1.7
Description	Wabash River Greenfield	Petroleum Coke IGCC Coproduction	Optimized Petroleum Coke IGCC Coproduction Plant				Optimized Coal to Power IGCC	Single Train Power		1,000 MW Coal IGCC Power Plant	Coal to Hydrogen
			Base Case	Min Cost	Spare Train	Next Plant		1.5A Coal	1.5B Coke		
Configuration											
Plant Location	Midwest	Gulf Coast	Gulf Coast	Gulf Coast	Gulf Coast	Gulf Coast	Midwest	Gulf Coast	Gulf Coast	Midwest	Midwest
Number of Air Separation Units	1	2	2	2	2	2	1	1	1	3	1
Number of Gas Turbines	1	2	2	2	2	2	1	1	1	4	0
Number of Gasification Trains	1	3	2	2	3	3	1	1	1	4	1
Number of Gasification Vessels	2	3	4	2	3	3	1	2	2	4	2
No of Syngas Processing Trains	1	3	2	2	2	2	1	1	1	2	1
Number of 50% H2 trains	NA	3	2	2	2	2	NA	NA	NA	NA	2
Design Feed Rates											
Feedstock Type	Coal	Pet Coke	Pet Coke	Pet Coke	Pet Coke	Pet Coke	Coal	Coal	Pet Coke	Coal	Coal
Coal or Coke, TPD as received	2,642	5,515	5,679	5,679	5,679	5,692	3,517	2,754	2,077	10,837	3,517
Coal or Coke, TPD dry	2,259	5,249	5,399	5,399	5,399	5,417	3,007	2,355	1,977	9,266	3,007
Feed, MMBtu HHV/hr	2,400	6,495	6,680	6,680	6,680	6,703	3,195	2,481	2,446	9,844	3,195
Feed, MMBtu LHV/hr	2,311	6,364	6,545	6,545	6,545	6,567	3,076	2,389	2,397	9,478	3,076
Flux, TPD	0	107	110.2	110.2	110.2	110.6	0	0	40.3	0	0
Water, gpm	2,790	4,830	5,146	5,146	5,146	5,146	3,079	2,840	2,525	9,752	2,457
Condensate, Mlb/hr	---	686	686	686	686	686	---	---	---	---	---
Oxygen, TPD of 95% O2	2,130	5,962	5,917	5,917	5,917	5,954	2,294	2,015	2,143	8,009	2,522 (99.5%)
Oxygen, TPD of O2	2,009	5,622	5,580	5,580	5,580	5,615	2,164	1,900	2,021	7,553	2,507
Design Product Rates											
Electric Power, MW	269.3	395.8	460.7	460.7	460.7	474.0	416.5	284.6	291.3	1,154.6	-18.4
Steam (750^{o}F/700 psig), lb/hr	---	980.0	980.0	980.0	980.0	980.0	---	---	---	---	---
Hydrogen, MMscfd	---	79.4	80.0	80.0	80.0	80.0	---	---	---	---	141.2
Sulfur, TPD	57	367	372	372	372	373	77	60	136	237	76
Slag (@ 15% water), TPD	356	190	195	195	195	195	462	364	71	1,423	474
Fuel Gas, MMBtu HHV/hr	---	363	0	0	0	0	---	---	---	---	---
Solid Waste to Disposal, TPD	---	---	---	---	---	---	3.0	---	---	---	---
Gas Turbine											
Type	GE 7FA	GE 7FA	GE 7FA+e	GE 7FA+e	GE 7FA+e	GE 7FA+e	"G/H-class"	GE 7FA+e	GE 7FA+e	GE 7FA+e	NA
Fuel Input, Mlb/hr	411.4	861.9	984.6	984.6	984.6	1,016.8	543.8	447.0	426.7	1,741.6	---
Heat Input, MMBtu/hr LHV	1,675	3,374	3,580	3,580	3,580	3,592	2,427	1,796	1,796	7,184	---
Steam Injection, Mlb/hr	111.0	164.2	429.1	429.1	429.1	395.7	620.1 of N2	246.8	272.3	1,037.8	---
Gross Power Output, MW	192	384	420	420	420	420	300	210	210	840	---
Cold Gas Efficiency (HHV), %	76.9	76.9	77.4	77.4	77.4	77.5	80.8	77.8	77.4	78.0	76.5
Steam Turbine Power, MW	118	118.8	150	150	150	164.3	164.1	113	121	465.2	70.6
Internal Power Use, MW	41	107	109	109	109	110	48	38.4	40.7	151	89.0
Heat Rate, Btu/kW-hr	8,912	NA	NA	NA	NA	NA	7,671	8,717	8,397	8,526	---
Thermal Efficiency, % HHV	38.3	NA	NA	NA	NA	NA	44.5	39.1	40.6	40.0	---
Emissions											
SOx as SO2, lb/hr	312	306	385	385	385	350	37	142	119	438	191
NOx as NO2, lb/hr	161	325	166	166	166	166	127	69	69	275	27
CO, lb/hr	56	111	105	105	105	106	47	41	41	161	1,846
Sulfur Removal, %	96.7	99.5	99.4	99.4	99.4	99.4	99.7	98.5	99.4	98.9	98.5
Performance Parameters											
Tons 02 / Ton of Dry Feed	0.889	1.071	1.034	1.034	1.034	1.037	0.720	0.807	1.022	0.815	0.834
Gross MW / Ton of Dry Feed	0.137	0.096	0.106	0.106	0.106	0.108	0.154	0.137	0.168	0.141	---
Net MW / Ton of Dry Feed	0.119	0.075	0.085	0.085	0.085	0.088	0.139	0.121	0.147	0.125	---
Emissions											
SOx (SO2) as lb/hr-MW	1.159	0.773	0.836	0.836	0.836	0.738	0.089	0.499	0.409	0.379	---
NOx (NO2) as lb/hr-MW	0.598	0.821	0.360	0.360	0.360	0.350	0.305	0.242	0.237	0.238	---
CO, lb/hr-MW	0.208	0.280	0.228	0.228	0.228	0.224	0.113	0.144	0.141	0.139	---
Daily Average Feed/Product Rates with Backup Natural Gas (Subtasks 1.1 and 1.7 are without Backup Natural Gas)											
Coal or Coke, TPD dry	1,705	4,635	4,310	3,973	4,814	4,842	2,400	1,826	1,546	7,018	2,470
Coal or Coke, % of design	75.5%	88.3%	79.8%	73.6%	89.2%	89.4%	79.8%	77.5%	78.2%	75.7%	82.2%
Power, MW	203.2	374.3	430.0	425.4	436.4	448.4	387.8	264.4	269.4	1,081	---
Power, % of design	75.5%	94.6%	93.3%	92.3%	94.7%	94.6%	93.1%	92.9%	92.5%	93.6%	---
Steam, lbs/hr	---	972.2	958.6	946.2	974.1	974.6	---	---	---	---	---
Steam, % of design	---	99.2%	97.8%	96.6%	99.4%	99.4%	---	---	---	---	---
Hydrogen, MMscfd	---	78.8	77.5	76.5	78.7	78.8	---	---	---	---	116.7
Hydrogen, % of design	---	99.2%	97.8%	96.6%	99.4%	99.4%	---	---	---	---	81.3%
Fuel Gas, MMBtu HHV/hr	---	360.1	0	0	0	0	---	---	---	---	---
Fuel Gas, % of design	---	99.2%	---	---	---	---	---	---	---	---	---
Natural Gas, Mscfd	NA	10,099	20,000	26,977	9,303	9,059	8,896	6,929	6,929	34,960	NA
Plant Cost, MM mid-2000 $[1]	452.6	993.2	764.0	746.0	812.6	787.3	464.7	375.0	367.0	1231.3	529.8
Plant Cost, $/design kW	1,681	NA	NA	NA	NA	NA	1,116	1,318	1,260	1,066	---
Required Electricity Selling Price for a 12% ROI, $/MW-hr[2]											
Without Natural Gas Backup	67.5	---	---	---	---	---	42.8	53.9	43.9	44.4	NA
With Natural Gas Backup	---	43.4	34.4	36.5	32.5	30.0	39.8	48.9	40.6	40.2	NA

NA = Not Applicable
January 8, 2002

1. All costs are mid-year 2000 EPC costs which exclude contingency, taxes, fees and owners costs. They are presented here to show the relative differences between cases. Current cost estimates should be developed for any proposed applications.
2. Power selling prices are presented to show a relative comparison between cases. The use of natural gas backup is described in Section II.4.2.

Chapter I

Introduction

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy to energy production from fossil fuels in the 21st century. The objective is to integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, and high value fuels and chemicals with virtually no emissions of air pollutants. Hopefully, it will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 builds on technology advancements being made in the Energy Department's Fossil Energy Program. It will integrate ongoing research and development in advanced coal and biomass gasification and combustion with next-generation fuel cells, high-performance turbine technology, and advanced coal conversion systems.

A *Vision 21* plant will be capable of using a variety of fuels, including coal and natural gas, perhaps mixed with petroleum coke, biomass, or municipal wastes. In contrast to today's single product energy facilities, a *Vision 21* plant could produce a multiple slate of products: electricity, liquid and/or gaseous fuels, and industrial-grade heat and/or steam.

In the Department of Energy's Fossil Energy Program. *Vision 21* will serve as a "roadmap" for future electric power and fuels research and development efforts. Key technologies will be developed as modules with the goal of combining them into highly flexible energy complexes. The *Vision 21* roadmap will establish technical specifications for integrating these modules. It will focus on the engineering challenges of reliability and operability of an integrated "energyplex." Furthermore, it will identify the research and development objectives that are needed to establish the technological foundation for an entirely new fleet of energy facilities that could be deployed in the 2010-2030 timeframe.

Specifically, the *Vision 21* goals are:

Power: Generating efficiencies greater than 60% using coal and greater than 75% using natural gas. For comparison, current coal technology is 33 to 35% efficient, and current natural gas technology is 45 to 55% efficient.

Combined Heat and Power: Overall thermal efficiencies of 85 to 90%.

Enviromental: Near zero emissions for all traditional pollutants, including smog- and acid rain-forming pollutants.

Greenhouse Gas Reduction: Carbon dioxide emissions reduced by 40 to 50% through efficiency improvements: reduced to zero (net) if coupled with carbon sequestration.

Coproducts: Clean, affordable transportation quality fuels at costs equivalent to an oil price of 20 $/barrel or less in 1998 dollars; also industrial-grade heat and/or steam and the potential for fuel-grade gas production.

Vision 21 will not be a single configuration. It will be a series of interconnected modules. Future designers will integrate these modules to meet specific market needs. A *Vision 21* plant might serve as the hub of an industrial complex, providing steam and/or heat in addition to electric power. Another *Vision 21* configuration might coproduce high-value chemicals or fuel gases for neighboring manufacturing facilities. Or it might be a power plant-coal refinery combination, producing electricity and liquid transportation fuels.

One of the core technologies in the Department of Energy's *Vision 21* program is coal gasification because it produces a gas stream that can be used as a source of

- energy to produce electric power, or
- hydrogen for fuel cells or chemical processes, or
- carbon and hydrogen for making high-value chemicals, or
- carbon and hydrogen for making high-quality liquid transportation fuels, or
- energy as a fuel gas for industrial plants.

This "Gasification Plant Cost and Performance Optimization" project, contract number DE-AC26-99FT40342, examines the current state-of-the-art of coal gasification to provide baseline design cases from which the Department of Energy can measure future progress towards achieving the *Vision 21* goals. This study also illustrates how advanced engineering design tools, previous design work, and operating experience acquired from the coal gasification demonstration plant can lower the plant cost and improve the overall project economics. Additional sensitivity cases were developed to demonstrate that petroleum coke gasification with hydrogen and steam coproduction is commercially ready and competitive. Operating experience from these commercial petroleum coke gasification plants will reduce the technical risk and the capital and operating costs of future coal gasification plants.

The Wabash River Repowering Project is the starting point for this study. The Wabash River project repowered an existing steam turbine by the addition of a Global Energy gasifier processing a nominal 2,500 tons/day of coal producing clean syngas for a General Electric MS 7001 7A gas turbine and steam for powering the existing steam turbine.

This project is divided into three tasks. Task 1 is work that primarily deals with gasification optimization using either coal or petroleum coke as fuel. The Optimized Coal IGCC Plant will only produce electric power. The Optimized Petroleum Coke IGCC Coproduction Plant will produce hydrogen and industrial-grade steam in addition to electric power. Task 2 will study coal and petroleum coke gasification plants that will produce liquid transportation fuel precursors in addition to electric power. If, implemented, Task 3 will examine conceptual designs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

The primary objective of Task 1 was to develop optimized engineering designs and costs for five Integrated Gasification Combined Cycle (IGCC) plant configurations. Starting from the as-built design, operation, and cost information from the commercially proven Wabash River Coal Gasification Repowering Project, the following eleven cases were developed:

- Wabash River Greenfield Plant.

- Non-optimized Petroleum Coke IGCC Coproduction Plant

- Optimized Petroleum Coke IGCC Coproduction Plants that will produce hydrogen and industrial-grade steam in addition to electric power (Subtasks 1.3 and 1.3 Next Plant – four cases)

- A future optimized Coal IGCC Plant producing only power using a next generation gas turbine (Subtask 1.4)

- Single-train Coal and Coke IGCC Power Plants (Subtask 1.5 – two cases)

- A Nominal 1,000 MW Coal IGCC Power Plant (Subtask 1.6)

- A Coal to Hydrogen Plant (Subtask 1.7)

Figure I.1 shows the chronological development of the above gasification plant designs.

In addition there are two other subtasks. Subtask 1.8 has the objective to develop a review of various warm gas cleanup methods that are applicable to IGCC systems. The Subtask 1.8 cases cover a variety of processes and provide a look at future syngas cleanup methods. Subtask 1.9 documents the method and results of the availability calculations for the design subtasks.

Task 2 has the objectives of developing optimized designs, cost estimates and economics for the following cases which will be built upon the Task 1 results.

- A Petroleum Coke IGCC Coproduction Plant producing liquid transportation fuel precursors in addition to electric power

- A Coal IGCC Coproduction Plant producing liquid transportation fuel precursors in addition to electric power

Similarly, Task 3 has the objectives of

- To evaluate two mid-term gasification plant power system options with the potential to meet the Department of Energy's *Vision 21* goals; 1.) incorporation of fuel cells, and 2.), carbon dioxide separation and collection.

- Additionally, conceptual designs and cost estimates for advanced IGCC power plant designs achieving efficiencies approaching 60% and incorporating CO_2 separation and collection shall be developed.

This report is the Topical Report for Task 1. It summarizes the individual task reports (which are included as appendices) and discusses the overall purpose, results and potential of this work. It is divided into the following chapters.

Chapter	Title
I	Introduction
II	Study Objectives and Methodology
III	Study Basis and Overview
IV	The Petroleum Coke Cases
V	The Coal Cases

VI	Environmental Impacts
VII	Market Potential and Future Applications
VIII	Summary and Recommendations
IX	Acknowledgements

Chapter II presents the objectives of this study and describes the methodology and Value Improving Practices procedures that were employed to achieve these objectives.

Chapter III presents the basis for the study and an overview of what was done.

Chapter IV summarizes the Subtask 1.2, Subtask 1.3, Subtask 1.3 Next Plant, and Subtask 1.5B petroleum coke-fueled power and coproduction plants.

Chapter V summarizes the Subtask 1.1, Subtask 1.4, Subtask 1.5A, Subtask 1.6, and Subtask 1.7 coal-fueled plants.

Chapter VI presents the environmental impacts of the IGCC cases.

Chapter VII discusses the market potential and future application of IGCC facilities.

Chapter VIII briefly summaries the Task I work and provides recommendations for further work

Chapter IX acknowledges the contributions of others.

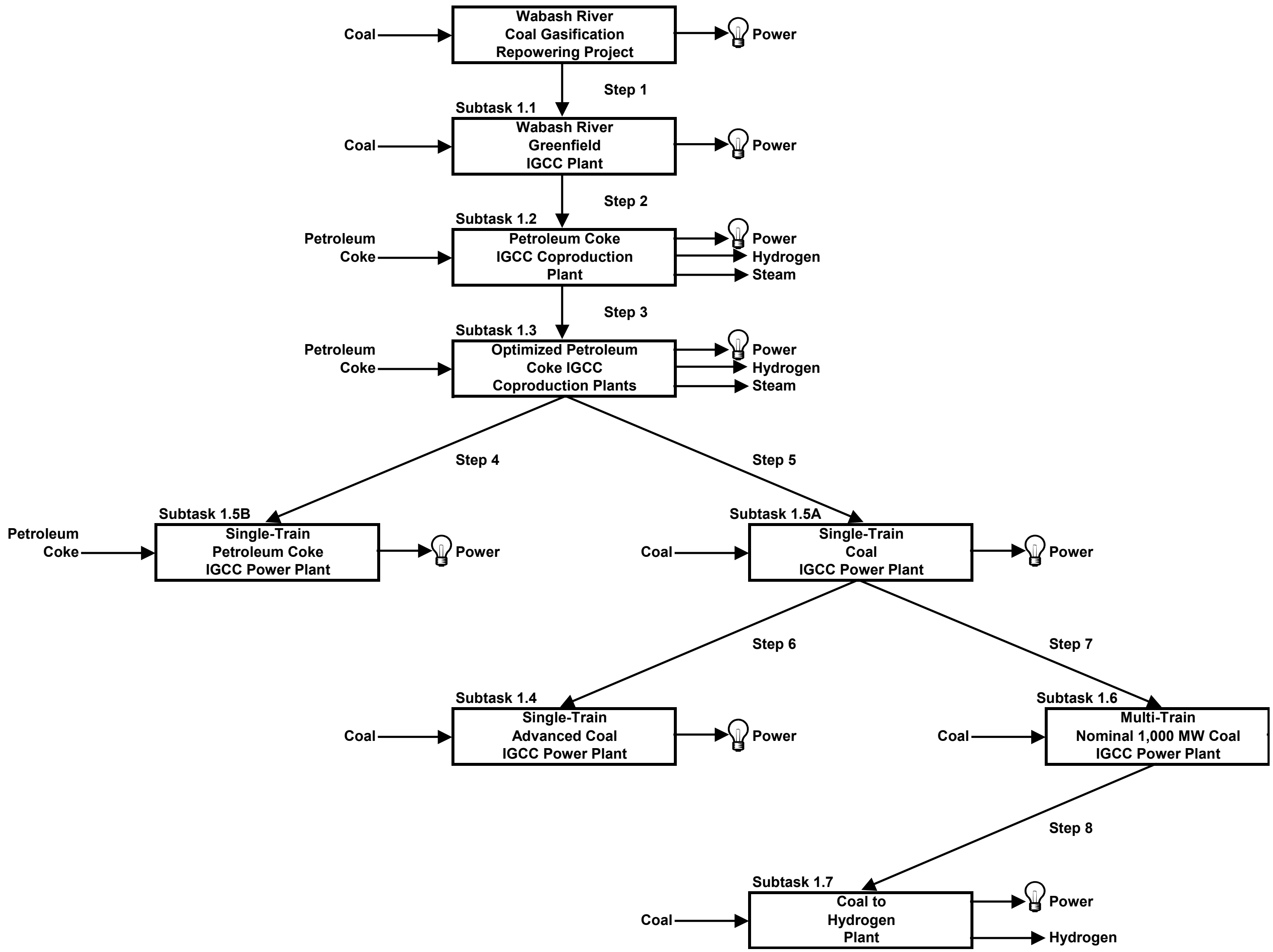
In addition this report contains the following Appendices.

Appendix	Title
A	Subtask 1.1 – Wabash River Greenfield Plant
B	Subtask 1.2 – Petroleum Coke IGCC Coproduction Plant
C	Subtask 1.3 – Optimized Petroleum Coke IGCC Coproduction Plant
D	Subtask 1.3 Next Plant – Next Optimized Petroleum Coke IGCC Coproduction Plant
E	Subtask 1.4 – Optimized Coal to Power IGCC Plant
F	Subtask 1.5 – Comparison of Coal and Coke IGCC Plants
G	Subtask 1.6 – Nominal 1,000 MW Coal IGCC Power Plant
H	Subtask 1.7 – Coal to Hydrogen Plant
I	Subtask 1.8 – Warm Gas Cleanup Review
J	Subtask 1.9 – Availability Analysis
K	Design Bases
L	Technical Publications

Because this report describes plant designs that are based on proprietary information, some key details are omitted. However, this report contains sufficient information to allow the reader to assess the performance of Global Energy's design for each subtask. Basic heat and material balance information can be found in the block flow diagrams and the tables. This information was taken from detailed PFD's and heat and material balances developed by the project team for each subtask. Design development included line sizings and marked up P&IDs for piping takeoffs. This information can be used to check the overall mass, carbon, and energy balances for the gasification plant and the power block, and possibly to adapt these to new cases. However, the project team, particularly Global Energy, would prefer to generate project specific mass and energy balances under a secrecy agreement. Such an agreement will allow Global Energy to provide additional details and to share confidential information.

Figure I.1

Schematic Diagram Showing the Chronological Development of the Gasification Plant Designs



Chapter II

Study Objectives and Methodology

II.1 Study Objectives

The objectives of this project are to examine the current state-of-the-art of coal gasification and to develop designs that will reduce the cost of power generated by IGCC plants by reducing their capital and operating costs, increasing their efficiency, and making them less polluting. Cases using a petroleum coke feedstock and coproducing hydrogen and steam also were developed as part of a market entry strategy for lowering the technical risk and the capital and operating costs of future coal gasification plants. A secondary benefit is to provide baseline cases from which the Department of Energy can measure future progress towards achieving their *Vision 21* goals.

The work is divided into three tasks. Task 1 is work that primarily deals with gasification optimization using either coal or petroleum coke as fuel. The Optimized Coal IGCC Plant will only produce electric power. The Optimized Petroleum Coke IGCC Coproduction Plant will produce hydrogen and industrial-grade steam in addition to electric power. Task 2 will study coal and petroleum coke gasification plants that will produce liquid transportation fuels in addition to electric power. Task 3 will examine conceptual designs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

Task 1 of this project has the objective to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations and a coal to hydrogen plant. Starting from the as-built design, operation, and cost information from the commercially proven Wabash River Coal Gasification Repowering Project, the following optimized cases were developed:

1. Optimized Petroleum Coke IGCC Coproduction Plants that will produce hydrogen and industrial-grade steam in addition to electric power (Subtasks 1.3 and 1.3 Next Plant – four cases)

2. A Coal IGCC Plant producing only power using a next generation gas turbine (Subtask 1.4)

3. Single-train Coal and Coke IGCC Power Plants (Subtask 1.5)

4. A Nominal 1,000 MW Coal IGCC Power Plant (Subtask 1.6)

5. A Coal to Hydrogen Plant (Subtask 1.7)

In addition there are two other subtasks which do not involve developing the design of an optimized plant. They are:

1. Subtask 1.8 – Review the status of warm gas clean-up technology as applicable to coal and/or coke fueled IGCC power and coproduction plants. The objective is to evaluate developing technologies that operate in the 300 to 750^{o}F temperature

range, preferably closer to 750°F, and to determine their potential economic benefit.

2. Subtask 1.9 – Discuss the Value Improving Practices availability and reliability design optimization program. Starting from historic Wabash River Repowering Project data, this subtask will discuss how the availability analysis and design considerations, such as the expected annual coke consumption, influence plant performance and sparing philosophy.

II.2 Background and Methodology

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE. Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period. Construction was started in July 1993, and commercial operation began in November 1995. The demonstration was completed in January 2000.[1,2]

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process is integrated with an existing steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries. The power block consists of an advanced General Electric MS 7001 FA gas turbine unit that produces 192 MW, a Foster Wheeler HRSG, and a 1953 vintage Westinghouse reheat steam turbine. The steam turbine, which was refurbished as part of the repowering project produces an additional 104 MW of power. Parasitic power is 34 MW giving a total net power output of 262 MW.

Since the initial startup of the Wabash River Repowering Project, many modifications and improvements have been made to the plant to improve plant performance and to increase availability. The net result of these changes has been a substantial improvement in plant operations. Furthermore, in addition to operation on Illinois coals, the plant has demonstrated successful and reliable operation on petroleum coke.

The design, construction, cost, and operational information obtained from this commercial facility provide the basic information for this project. That is, the sum total of knowledge

[1] Topical Report No. 20, "The Wabash River Coal Gasification Repowering Project – An Update," U. S. Department of Energy, September 2000

[2] Global Energy, Inc., "Wabash River Coal Gasification Repowering Project – Final Report," September 2000.

gained from the plant starting from the initial design through current operations on both coal and petroleum coke have been studied to compile relevant information for this project. Current performance information was analyzed to develop a heat and mass balance model representing the present day plant configuration that was the basis for developing appropriate models for the subsequent subtasks. As-built cost information was obtained and provided the cost basis for the cost estimates. Because the cost estimates are based on actual equipment purchases and construction labor use, the resulting cost estimates are more accurate than typical estimates would be for this type of study. Availability and reliability information from the final year of the DOE demonstration period were the basis for the availability analyses.

The optimization studies for the Subtask 1.3 and Subtask 1.4 plants were done using the structured Value Improving Practices Program promoted by Independent Project Analysis, Inc.

Figure II-1 is a schematic diagram of the steps involved in developing the design, cost and economics for a specific case. Appendix K contains the design bases technical work plans for Subtasks 1.1 through 1.7. Based on these design bases and work plans, detailed, elementally balanced process simulation models were developed for each case by Global Energy using their proprietary process simulation program. This is a very detailed process simulation program that simulates the various heat exchange and steam generation steps within the gasification area. These model generated heat and material balances were then feed to the GT Pro simulation program for a detailed simulation of the combined cycle block.[3] The detailed model results are proprietary. However, this report and the appendices contain sufficient information for verification of the carbon, slag, sulfur, and heat balances.

Based on the model results, P&IDs, sized equipment lists, line sizings, and other information necessary to calculate the plant cost were developed. The mid-year 2000 plant cost was built up based on detailed cost information from the as-built Wabash River Repowering Project (adjusted for inflation), selected equipment quotes, information from similar, current Bechtel projects, and from Bechtel's in-house data bases. Because the fundamental cost information is based on the Wabash River Repowering Project, the resultant cost estimates are deemed to have a low uncertainty.

Availability analyses were calculated based on the design configuration to determine the annual production rates (capacity factors). The cost and capacity information along with operating and maintenance costs, contingencies, feed and product prices, and other pertinent economic data were entered in a discounted cash flow economic model. This model then was used to generate the return on investment (ROI), cost of electricity, and sensitivities.

Global Energy's operating personnel developed the operating and maintenance costs based on Wabash River experience. This is proprietary information.

In some cases, such as in the development of the Subtask 1.3 minimum cost and spare gasification train cases, iterations were made back to the to the block flow diagrams to examine the effects of replicated equipment and the addition of a spare gasification train.

[3] GT Pro is a proprietary simulation program by Thermoflow Inc., Wellesley, Mass.

II.3 Value Improving Practices

Value Improving Practices (VIPs) are focused activities aimed at removing unnecessary investment from a project scope.

Eleven industry standard VIPs were benchmarked by Independent Project Analysis, Inc. (IPA). Eight of these were selected for this project. In addition, a ninth item was added, Plant Layout Optimization. This item encompasses schedule optimization and some aspects of constructability also. These nine items are:

1. Technology Selection
2. Process Simplification
3. Classes of Plant Quality
4. Value Engineering
5. Availability (Reliability) Modeling
6. Design-to-Capacity
7. Plant Layout Optimization
8. Schedule (Construction and Procurement) Optimization
9. Operating and Maintenance Savings

Value Improving Practices have proven to very successful over the years for reducing the cost of facilities, improving their efficiency, conserving raw materials, and being beneficial in many other ways. They generally are implemented in the project development stage when there is time pressure to get the project completed, and therefore, only a specific amount of time is allowed for the VIP procedures. In many of these situations, the full benefit of the VIP procedures is not realized. Because of this, there are advantages of doing the VIP procedures “off-line” where there no time pressure for completion in order to maintain the project schedule. It is in this spirit that the VIPs were applied to Global Energy’s IGCC process to develop substantially improved and optimized designs.

The detailed results of the entire VIP exercise for the Subtask 1.3 and 1.4 IGCC plants are documented in a confidential VIP report.

II.3.1 Technology Selection

Technology Selection is a formal, systematic process by which a company searches for production technologies outside the company (or, in some instances, in other divisions within the company) that may be superior to that currently employed in its manufacturing plants. The hydrogen recovery process was identified as a candidate for an alternate technology.

II.3.2 Process Simplification

Process Simplification is a disciplined, analytical method for reducing investment costs (and often operating costs, as well) by combining or making unnecessary one or more chemical or physical processing steps. The following items are the focus of process simplification.

- Straight through processing
- Eliminate reworking and blending
- Process flexibility, if appropriate
- Process involves collecting data
- Cycle times

- Process efficiency
- Product sequence length
- Minimum lot sizes

Part of process simplification involves the application of critical spare pieces of equipment and subtle design features which seem to increase complexity, but actually are required to allow the plant to have a high operating factor. The specific details of these design features are considered proprietary.

II.3.3 Classes of Plant Quality

Classes of Plant Quality establishes what quality facility is needed to meet business goals. It adjusts reliability, expandability, automation, life of the facility, expected stream factors, likelihood of expansion, production rate changes with time, production quality, and product flexibility. The classes of plant quality can be used to determine the needed design allowance, redundancy, sparing philosophy, and room for expansion.

This VIP practice is one of the most critical to the success of a cost reduction program and, in order to be effective, it must be completed and documented very early in the project, i.e.; before design begins and before other VIPs are implemented.

This VIP forms the foundation for the plant's design basis / basic design criteria and provides the framework for implementing other VIPs.

Table II.1 shows the four categories of classes of plant quality. They are somewhat arbitrary, and generally, are not necessarily quantifiable.

II.3.4 Value Engineering

The application and implementation of the value engineering methodology on Bechtel projects follows the value engineering job plan recommended by the Society of American Value Engineers (SAVE). This plan covers three major periods of activity: *Pre-Study*, the *Value Study*, and *Post-Study*. The SAVE job plan outlines specific value engineering steps necessary to effectively analyze a project and to develop the maximum number of alternatives to achieve the project's required functions. Value engineering's goal is to obtain the lowest cost without sacrificing function, performance, or the ability of a facility to carry out its specific mission. This goal is accomplished by:

- Ensuring the owner's objectives are met by the design (see VIP Classes of Plant Quality)
- Identifying and removing items that add cost without contributing to function
- Studying the total cost of owning, operating, and maintaining the facility
- Performing an analysis that defines a function, establishes a monetary worth for that function, and then provides that function at the lowest cost

A Bechtel in-house facilitator led a value engineering workshop for this project. Almost 300 ideas were generated during the brainstorming session. This list was categorized, and the best ideas were evaluated by various value engineering teams. These teams represented the Wabash River operating and maintenance staff, Global Energy's gasification specialists, a cross-section of Bechtel's design and construction specialists, and Nexant's specialists.

II.3.5 Availability (Reliability) Modeling

Reliability modeling uses computer simulation of processes to explore the relationship between the maximum production rates, design parameters, and operational factors such as quality, yield, production transitions, maintenance practices and requirements, capacity, safety, and environmental concerns.

The objective of this practice is to quantitatively assess the availability of either all or part of a project and to identify major contributors to forced downtime.

Availability models were developed for all the plant configurations of Subtasks 1.1 through 1.7 based on the availability information given in the final report for the Wabash River Repowering Project.[2] The model results allowed the prediction of the expected capacity factors (annual production rates) for prediction of the annual revenue and expense streams. This information was fed to the discounted cash flow model to evaluate the NPV and/or ROI for the various Subtask designs.

II.3.6 Design-to-Capacity

Designing-to-capacity evaluates the true required maximum capacity of each major piece of equipment relative to the desired overall facility capacity. Often equipment is designed with a "design factor" that results in larger equipment and additional capacity. This conservatism can lead to certain equipment or whole plants having overcapacity, which the business may or may not want to pay for initially. Excess processing capacity can be incorporated into designs because of uncertainties in future feed slates, physical properties, expectation of future capacity increases, and equipment design uncertainties.

Design-to-Capacity can be affected by the following items:

1. Sequential engineering steps such that can each add some design conservatism, that when compounded can add considerable excess capacity.
2. Uncertainties in correlations for such things as physical properties, heat transfer coefficients, column tray efficiencies, and reactor space velocities.
3. Variations in design methodology and procedures.
4. Replacing industry and project standards
5. Design specifications that do not directly influence capacity issues such as corrosion allowances.
6. Removing "extra fat" to meet guarantees associated with licensing agreements.

The Design-to-Capacity process saves capital cost by helping designers to fully understand the operability of every step and equipment item. Conservatism in design, as with too much storage capacity, is a way of covering uncertainties. It also forces the explicit thinking about capacity and expandability. Design-to-capacity removes that flexibility or robustness to handle variations that operating personnel may have gotten used to having. It also limits the amount of capacity that can be gained by debottlnecking.

The Design-to-Capacity process is strongly linked to the Classes of Plant Quality VIP (Project Objectives) process so it is recommended to start both processes at the same kickoff meeting early in the initial design phase. Project objectives should be agreed to first, and then be followed by a discussion of Design-to-Capacity issues. Both methodologies involve business, operating, and technical people discussing options and then assigning different categories or levels to various criteria. This objectively frames what the project is trying to accomplish in terms of meeting business expectations.

II.3.7 Plant Layout Optimization

Plant Layout Optimization formalizes the process of developing a plant layout that will satisfy the project needs at minimum life cycle cost. The items that this VIP brings into consideration include:

- Accessibility during construction
- Accessibility during maintenance
- Accessibility during operations
- Minimization of interconnecting piping
- Safety
- Layout codes and regulations
- Provisions for modifications and expandability
- Integration with the surrounding community

During the development of the plant layout design, balancing all the above items becomes somewhat subjective in nature because of the inability to quantify various items. For this project, the amount of interconnecting piping was used as the measure of quantification.

II.3.8 Schedule (Construction and Procurement) Optimization

Schedule Optimization consists of analysis of the design, usually performed by experienced construction personnel, to save time and reduce costs during the construction phase.

As defined by the Construction Industry Institute (CII), this involves:

> *"The optimum use of construction knowledge and experience in planning, design, procurement, and field operations to achieve overall project objectives."*

Bechtel's approach is not only the review of design drawings; it is also the early integration of construction input into planning, design, and engineering processes. Bechtel recognizes that construction input during early project planning will:

- Allow system turnover requirements and construction needs to drive the overall project schedule from back to front
- Make constructability an integral part of project execution plans
- Actively include construction knowledge in project planning
- Obtain construction's essential involvement when developing contracting strategies
- Provide consideration for previously proven construction methods in basic design approaches
- Promote efficient construction operation and maintenance through effective site layouts

This input positively influences cost reduction through:

- Designs configured to enable efficient construction and startup
- Standardized design elements to enhance constructability
- Design and procurement schedules that support the EPC schedule
- Development of modularization and pre-assembly plans that facilitate fabrication, transport, and installation

- Design that facilitates construction under adverse weather or site conditions
- Reduced startup duration

Bechtel implements procurement optimization by forming supplier alliances to allow cost savings by placing larger orders with selected quality suppliers. Bechtel has several multi-project acquisition groups which specialize in various areas, such as pipe, pumps, heat exchangers, structural steel, etc.

II.3.9 Operating and Maintenance Savings

All Operating and Maintenance Savings go directly to the bottom line. Thus, anything that can be done to reduce these expenses results in increased profit. This VIP is closely aligned with the reliability modeling VIP and requires significant input from plant operations and maintenance. Therefore, Wabash River operating and maintenance personnel were part of the VIP team that developed and evaluated numerous ideas for maintenance savings. These ideas included such things as improved access to various plant sections, redesign of certain equipment, selection of more reliable equipment, revised metallurgy in selected plant sections, relocating equipment, permanently installed cranes, allowances in certain exchangers, etc. These ideas were evaluated and design modifications were made to incorporate those that were economically sound.

The actual operating and maintenance cost estimates and the improvements attributable to the application of the VIPs are proprietary. They are documented in the confidential Value Improving Practices report.

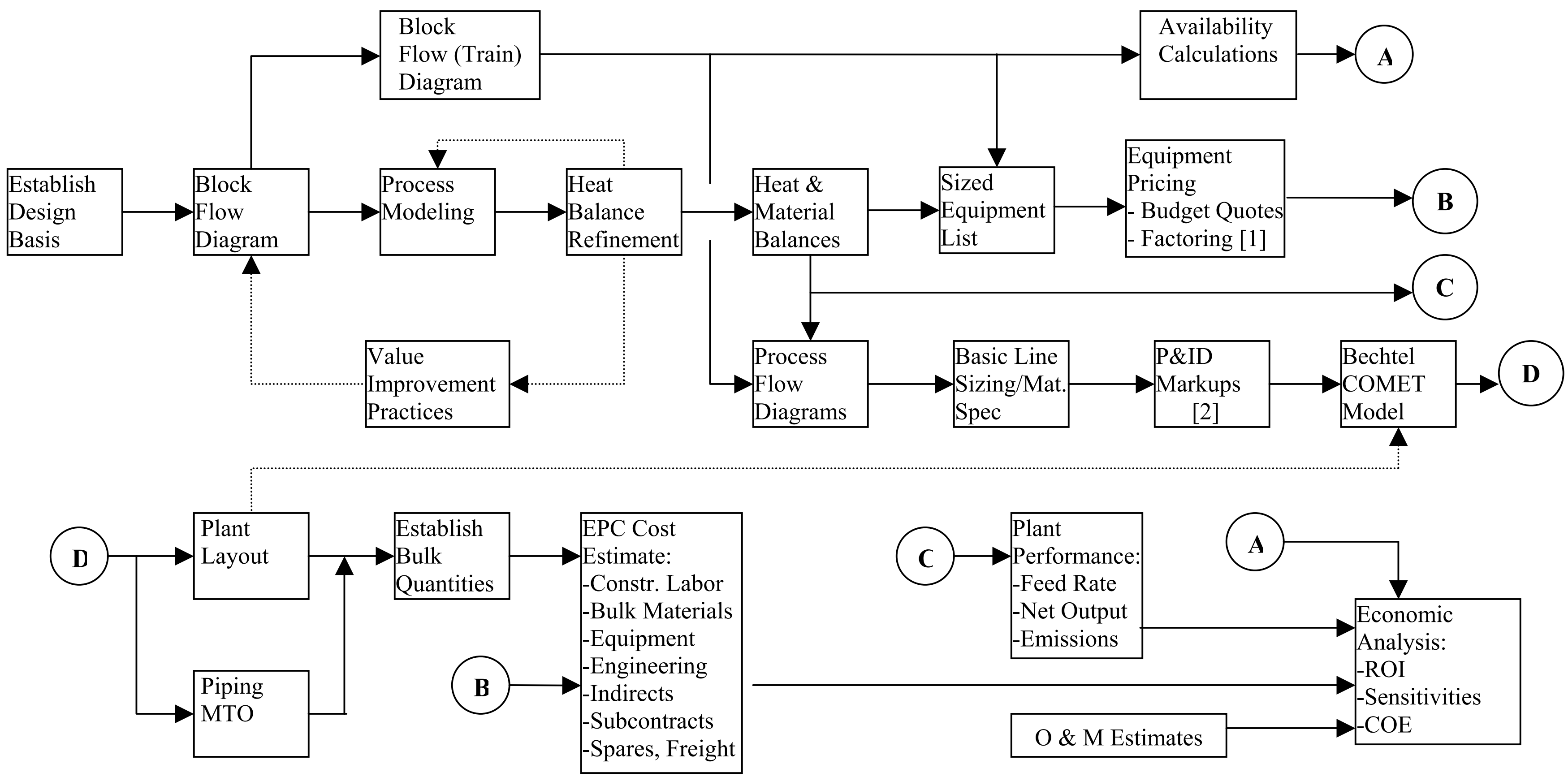
Table II.1 – Part 1
CLASSES OF PLANT QUALITY OBJECTIVES - ONSHORE FACILITIES
PERFORMANCE CHARACTERISTICS OF VARIOUS DESIGN CATEGORIES

	Category I	Category II	Category III	Category IV
PROCESS CHARACTERISTICS				
Capacity	Designed for a specific capacity with one feedstock and one set of operating conditions. No capacity allowance for deterioration of mechanical integrity or process performance over the life of the plant.	Designed for a specific capacity and feedstock with allowances for different operating conditions and deterioration of mechanical integrity. If operated outside stated conditions, capacity may be impaired.	Designed for multiple, but similar feedstocks at a given feedrate. Difficult to replace major equipment sized with overcapacity.	Designed for multiple feedstocks and feedrates as well as start-of-run and end-or-run conditions; hence overcapacity expected in most cases.
Product Quality	Designed to meet product specifications at given set of conditions only.	Expect to meet product specifications though when operating outside stated conditions may have to compromise on rate or other parameter. No specification overcapacity provided.	Expect to meet product specifications. Difficult to replace major equipment impacting quality; designed conservatively.	Designed with assurances that product specifications will be met; hence exceed quality requirements at design conditions.
Unplanned Flexibility	No planned (or designed) flexibility to handle off design conditions. Additional expenditures likely as experience gained. Very limited turn down.	Only minimal flexibility to meet off design conditions. Additional expenditures likely as process requirements change.	Moderate flexibility and turndown. Additional expenditures necessary to utilize full capacity of that equipment conservatively designed.	Broad flexibility and large turndown. Future expenditures probably minimal even to realize most major equipment maximums.
Marginal Investment Criteria	Not normally considered even when high payout.	Consider only for high payout.	Not less than base project investment criteria including consideration of usable plant life.	Limited by Corporate capital "hurdle"; i.e., earning power could be less than that of base project. Long plant life and/or early full capacity needed.
Expandability	Tight plot space with low first cost orientation. Debottlenecking and modifications to improve or change performance may be difficult if possible at all.	Tight, low first cost debottlenecking may be difficult. Consideration may be given to potential future changes to improve performance.	Somewhat more open space to improve accessibility and permit modest changes for debottlenecking and product improvement.	Open plot with provision to isolate sections for maintenance. Room for process and capacity modifications.

Table II.1 – Part 2
CLASSES OF PLANT QUALITY OBJECTIVES - ONSHORE FACILITIES
PERFORMANCE CHARACTERISTICS OF VARIOUS DESIGN CATEGORIES

	Category I	Category II	Category III	Category IV
PLANT CHARACTERISTICS				
Reliability	Sparing limited to applications necessary for an orderly shutdown. Stream factor is <80%.	Sparing generally limited to applications necessary for orderly shutdown or where experience with similar services indicates frequent plant outages for repairs are likely. Consideration given to imposing special conditions on particular equipment as an alternative to sparing, installing bypasses, etc. Stream factor: 85-90%.	Spares applied for orderly shut down, in services known to need frequent maintenance and requiring plant outages, or necessary to keep the plant in a "ready" position while repairs are made. Consideration given to imposing special conditions on particular equipment as an alternative to sparing, etc., or if the equipment is non-redundant and critical to the basic plant operation. Stream factor 90-95%.	Spares, etc., applied in most applications to maintain basic plant operations at or near design conditions during component maintenance. Industry standard equipment and minimal sparing applied to sections that are intended to optimize plant performance but do not impact basic product out-turn. Stream factor 95+%.
Controls and Data Provisions	Simple. Intended for operating at design case only. Heavy reliance on operating personnel. No provision for specified turn down, optimization, or troubleshooting. Minimal data collection.	Simple. Intended for primarily operating at design conditions. Some recognition of needs for operating modestly outside design case. Heavy reliance on operating personnel. Connections provided for temporary hookups of instruments for trouble-shooting/optimization studies. Minimal data collection.	Moderate number of control loops; reliance on operators reduced during normal operations. Sufficient equipment and data collection for troubleshooting and frequent optimization studies. Extent of this equipment tempered by knowledge and experience with the process.	Complex with sophisticated systems. Less reliance on operators especially out in the field. Sufficient equipment for continuous, or nearly continuous optimization and performance studies, including variations of process variables. Extensive data collection, handling & retention. Provision of or for computer information and/or control.
Maintenance	Minimal, if any, maintenance facilities included in the original plant. Accessibility for mobile equipment may be limited. Major maintenance expenditures may be necessary if plant is to continue operation more than 2-5 years. High maintenance costs.	Maintenance facilities installed only where experience with this type of plant dictates. Accessibility for mobile equipment may be limited. Major maintenance expenditures may be necessary if plant is to continue operation more than 4-6 years.	Maintenance facilities and accessibility for mobile equipment provided where experience with this type of plant dictates. Space also provided for difficult maintenance jobs during normal life of unit.	Need for temporary maintenance facilities minimized and accessibility for wide use of mobile maintenance equipment provided. Justifications for facilities based on anticipation of a long plant life. Major maintenance costs not contemplated over a long plant life.
Life	2 - 5 years.	5 - 10 years.	10 - 20 years	20+ years.

Figure II-1
TASK DEVELOPMENT METHODOLOGY



Notes:
[1] All critical process equipment costs in Gasification Train, plus ASU (Subcontract) are derived from budget quotations
[2] Markups (line size, spec, # trains, eqiup. add/delete) for all lines $\geq$ 2”

II.4 Availability Analysis

The common measures of financial performance, such as return on investment (ROI), net present value (NPV), and payback period, all are dependent on the project cash flow. The net cash flow is the sum of all project revenues and expenses. Depending upon the detail of the financial analysis, the cash flow streams usually are computed on annual or quarterly bases. For most projects, the net cash flow is negative in the early years during construction and only turns positive when the project starts generating revenues by producing saleable products. However, a plant is generating revenue only when it is operating and not when it is shut down for forced outages, scheduled maintenance, or repairs. Therefore, the yearly production (total annual production) is a key parameter in determining the financial performance of a project.

Although the design capacity is the major factor influencing the annual production, other factors that influence it include scheduled maintenance, forced outages, equipment reliability, and redundancy. In order to predict the annual revenue stream, an availability analysis that considers all of the above factors must be performed to predict the annual production and annual revenue streams to develop a meaningful financial analysis.

On this basis, an availability analysis was performed on each of the cases considered in Task 1 of this study to determine the applicable revenue streams and the ROI.

Appendix J contains a detailed description of the availability analysis studies and their results. Attachment A, Availability Nomenclature, of Appendix J contains definitions of availability related terms as proposed by the Gasification Technology Council. This table is supplemented with additional terms as used in this study.

II.4.1 Availability Analysis Basis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[2] This information is summarized in Table 1 of Appendix J. During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After three adjustments, this data was used to estimate the availability of the Task 1 coal and petroleum coke IGCC plant designs. The first adjustment increased the availability of the air separation unit (ASU) from the observed availability of 96.32% to the industry average availability of 98%. The second adjustment was to improve the availability of the first gasification stage by negating the impact of a slag tap plugging problem caused by an unexpected change in the coal blend to the gasifier. For the Subtask 1.2 and 1.3 plants, this adjustment is justified since a dedicated petroleum coke plant would be very unlikely to experience this problem. The third adjustment eliminated a short outage that was caused by a service interruption in the water treatment facility because sufficient treated water storage will be available to handle this type of outage.

Based on the reported Wabash River data, availability analyses were calculated using the EPRI recommended procedure.[4] This procedure calculates availabilities based only on two plant states, operating at design capacity or not operating. For a single train plant with all the units in a series configuration (i.e.; no redundancy), the overall plant availability simply is the product of the availability of all the individual unit availabilities. For multiple trains (or for plant sections with spare units), the EPRI report presents mathematical formulas based on a probabilistic approach for predicting the availability of all trains or of 1 of 2, 2 of 3, 1 of 3, etc. Appropriate combinations of these mathematical formulas are used to represent plants with some portions containing multiple trains or spare equipment and other portions being single trains.

Since the objective of this availability study is to determine the projected annual revenue stream, this study does not differentiate between forced and scheduled outages. In other words, it is immaterial whether the plant is off line because of a forced outage as the result of an equipment malfunction or whether it is off line because of a scheduled outage for normal maintenance or refractory replacement. Consequently, the annual availabilities reported in this study will be lower than those studies which do not consider scheduled outages.

II.4.2 Use of Natural Gas

To improve the yearly power output from single train gasification plants, backup natural gas is used to fire the gas turbine to make power when syngas is unavailable. Thus, for most of the year power is made from the lower cost coal, but for those times when the syngas generation portion of the plant is unavailable and the economics are favorable, power can be produced from higher priced natural gas. Multiple train power plants can be operated in a similar manner when insufficient syngas is available to fully load all the gas turbines.

The situation with the Subtask 1.2 and 1.3 petroleum coke coproduction plants is somewhat different. The gasification trains in these plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to fully fire one combustion turbine. Thus, in this situation, natural gas is used to supplement the syngas and fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption in the plant also is reduced when one gasification train is not operating by its internal power consumption and that of one air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

In the less frequent situation when only one syngas train is operating and only one combustion turbine is operable, backup natural gas also is used to fully load the available gas turbine while supplying the design hydrogen and steam demands. In this situation, the export power produced by the plant is about half the design rate. Supplemental firing with natural gas in the HRSG is not considered.

[4] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems*, Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304, August 1985.

In the least likely situation when both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire the gas turbine and produce export electric power from both the combustion turbine and the steam turbine. In this case, the amount of export power will be greater than that of the design capacity of the gas turbine because the reduced internal power loads are more than covered by the power produced by the steam turbine.

For Subtasks 1.2 through 1.6, the average daily natural gas rates were calculated as part of the availability analysis and are shown later in this report. Natural gas usage during startup and during maintenance operations, such as for curing refractory, are not considered in the availability analysis calculations, but are included in the operating and maintenance costs during the financial analysis.

II.5 Commodity Pricing

At the start of this project in early 2000, the economic and financial environment for the discounted cash flow evaluations of this project was assumed based on reasonable future projections. This set of economic conditions was used for all the discounted cash flow financial analyses performed in this study. Table II.2 contains a list of most of these economic assumptions. The commodity prices are based on long term projections for the U. S. Gulf Coast (except the coal price which is a Mid-West price). In this price structure, the hydrogen and steam prices were set based on their cost of production from 2.60 $/MMBtu natural gas. Also, an in-house combined cycle model predicts a required electricity price of about 35 $/MW-hr for a 12% after tax ROI with natural gas at 2.60 $/MMBtu. The inflation rates generally are based on the Energy Information Administration's *Annual Energy Outlook 2001.*[5]

However, since the time when these commodity prices were set, the economic scenario has changed. Natural gas prices have spiked to 9-10 $/MMBtu and now are dropping back to values that are below 3.00 $/MMBtu.[6] Oil prices have declined as a result of the world wide economic slowdown. Interest rates in the United States are the lowest that have been in over 40 years. Electricity deregulation is occurring and its effect on the utility market is unknown. The *Annual Energy Outlook 2001* shows a current industrial power price of about 40 $/kW-hr and an average residential power price of about 84 $/kW/hr with the average to all users being about 60 $/kW-hr. Furthermore, over the next 20 years the Energy Information Administration predicts a 0.5%/year decrease in power prices (on a current dollar basis). This study inflated the cost of electricity at 1.7%/year which is 2.3% less than the general inflation rate. On a constant dollar basis this is a 0.6% annual decrease. Thus, the economic projections used in the study are slightly conservative.

Therefore, although this assumed economic and financial environment was reasonable when it was proposed, it should not be used to evaluate proposed projects. Each project should be evaluated using a project specific economic scenario that is appropriate for its situation. For example, one coproduction project may set a high value on steam because it

[5] U. S. Department of Energy, Energy Information Administration, "Annual Energy Outlook 2001 with Projections to 2020", December 2000, www.eia.doe.gov/oiaf/aeo.

[6] Oil and Gas Journal, page 6, Sept 10, 2001, and Houston Chronicle, page 9D, Dec 9, 2001.

Table II.2
Basic Economic Parameters

Feeds	Price	Inflation, %/yr
Petroleum Coke, $/ton	0 $/ton	0
Coal	22.0 $/ton	1.2
Flux, $/ton	5.0 $/ton	1.7
Natural Gas, HHV	2.6 $/MMBtu	3.9
Products		
Electric Power	Calculated*	1.7
Hydrogen	1.3 $/Mscf	3.1
Steam	5.6 $/tom	3.1
Fuel Gas	2.6 $/MMBtu	3.9
Sulfur	30.0 $/ton	0
Slag	0 $/ton	0
Other Financial Parameters		
General Inflation	2.3 %/year	
Loan Amount	80%	
Loan Interest Rate	10 %/year	
Loan Financing Fee	3%	
Owner's Contingency	5 % of EPC cost	
Development Fee	1.2 % of EPC cost	
Start-up Cost	1.5 % of EPC Cost	
Income Tax Rate	40%	

* Electric power prices are calculated to yield a given return on investment. They are reported on a current day cost; i.e., the cost at the time when construction begins.

will replace an antiquated power plant, and another may have little use for steam other than to generate power.

II.6 Financial Analysis

For all cases a financial analysis was performed using a discounted cash flow (DCF) model that was developed by Bechtel Technology and Consulting (now Nexant Inc.) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[7] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects.

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data that are directly related to the specific plant as follows.

<u>Data Contained on the Plant Input Sheet</u>

- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses
- Contingency, fees, owners cost, and start up expenses.

The Scenario Input Sheet contains data that are related to the general economic environment that is associated with the plant as well as some data that are plant related. The data on the Scenario Input Sheet are shown below.

<u>Data Contained on the Scenario Input Sheet</u>

- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Startup information

For all cases, the EPC spending pattern was adjusted to reflect forward escalation during the construction period since the EPC cost estimate is an “overnight” cost estimate based on mid-year 2000 costs.

Finally, items that were excluded in the cost estimate, such as spares, owners cost, contingency and risk are included in the financial analysis.

The appendices contain filled in data input sheets for the discounted cash flow financial model for most of the cases. However, in all cases, the operating and maintenance cost information has been omitted because it is considered proprietary and highly confidential.

[7] Nexant, Inc., “Financial Model User’s Guide – IGCC Economic and Capital Budgeting Evaluation”, Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Chapter III

Study Basis and Overview

III.1 Study Basis

Global Energy's experience in the design, construction, and operation of the Wabash River Coal Gasification Repowering Project is the primary input which forms the foundation or basis for this study.[1] This project involved the repowering of a 1953 steam turbine with a Global Energy gasifier and a General Electric MS 7001 FA gas turbine. The design, construction, cost and operational information from this commercial facility are the starting point from which the subsequent designs were developed.

The design bases for the various subtasks are shown in Appendix K and in the various subtask reports. These design bases were developed starting from the as-built Wabash River facility to generate the Subtask 1.1 Greenfield Pant and then move it to the Gulf Coast to develop the Subtask 1.2 Petroleum Coke IGCC Coproduction Plant. The plant designs for the next five subtasks followed from these two original cases.

III.2 Project Overview

Task 1 of this project consisted of ten subtasks, numbered 1 through 9. Subtask 1.3 is divided into two parts, Subtask 1.3 and Subtask 1.3 Next Plant, which contain four subcases. Subtask 1.3 Next Plant and Subtasks 5 through 9 were added after the work had started. These nine subtasks and the appendices in which they are documented are:

1. Subtask 1.1 – Expand the Wabash River repowering project to a greenfield facility. Develop a cost estimate and economics for the greenfield facility based on the Wabash River design. (Appendix A)

2. Subtask 1.2 – Develop a design, cost estimate, and economics for a Petroleum Coke IGCC Coproduction Plant coproducing hydrogen and industrial-grade steam in addition to electric power. (Appendix B)

3. Subtask 1.3 – Develop a design, cost estimate, and economics for an Optimized Petroleum Coke IGCC Coproduction Plant coproducing hydrogen and industrial-grade steam in addition to electric power. (Appendix C)

4. Subtask 1.3 Next Plant – Develop a design, cost estimate, and economics for the Next Optimized Petroleum Coke IGCC Coproduction Plant coproducing hydrogen and industrial-grade steam in addition to electric power. (Appendix D)

5. Subtask 1.4 – Develop a design, cost estimate, and economics for a future single-train Optimized Coal IGCC Power Plant. (Appendix E)

6. Subtask 1.5 – Comparison between single-train coal and petroleum coke fueled IGCC power plants highlighting the major differences between the designs,

[1] Global Energy, Inc., "Wabash River Coal Gasification Repowering Project – Final Report," September 2000.

developing cost estimates, and doing a financial analysis for each case and comparing the results with those from Subtask 1.1. (Appendix F)

7. Subtask 1.6 – Develop an optimized design and cost estimate for a nominal 1,000 MW coal fed IGCC power plant using GE 7FA+e combustion turbines and perform a financial analysis. (Appendix G)

8. Subtask 1.7 – Develop an optimized design and cost estimate for a single-train coal to hydrogen plant processing the same amount of coal as the Subtask 1.4 design and perform a financial analysis. (Appendix H)

9. Subtask 1.8 – Review the status of warm gas clean-up technology as applicable to coal fueled IGCC power and coproduction plants. The objective is to evaluate developing technologies that operate in the 300 to 750^{o}F temperature range, preferably closer to 750^{o}F, and to determine their potential economic benefit. (Appendix I)

10. Subtask 1.9 – Discuss the Value Improving Practices availability and reliability design optimization studies. Starting from historic Wabash River Repowering Project data, this subtask will discuss how the availability analysis and design considerations, such as the expected annual coke consumption, influence plant performance and sparing philosophy. (Appendix J)

The results of each subtask are described in detail in the separate appendix that is listed following the above brief description of each subtask. Table III.1 summarizes the results of the eleven IGCC plant design cases that were examined in this study. The main results will be discussed in the following two chapters. This table is presented here to provide an overview of the cases and to be used as a reference for the following chapters.

III.3 Heat Integration

Integrated Gasification Combined Cycle (IGCC) or IGCC with coproduction (IGCP), as the name implies, is the integration of two primary process blocks, gasification and combined cycle power generation. Integration refers to the sharing of heat such as high pressure steam from the high temperature heat recovery unit, and possibly, the production of other byproducts, such as hydrogen. The optimum use of heat has been extensively studied.[2] Figure III.1 shows the overall input streams, output streams, and integration streams between the gasification block, hydrogen production facilities, and the combined cycle power block for the Subtask 1.3 Next Plant. It is the efficiency of the individual pieces and the sharing of energy between the pieces that determines the plant output and efficiency. From the overall energy balance and the information in the individual reports (Appendices A through G), it can be shown that most of the fuel (coal or coke) energy is used to make power. The energy balances also show that most of the energy going to power is available to the combined cycle or high pressure steam systems. Most of the low level energy is used effectively for syngas moisturization. Very little low level energy is recovered in the bottoming cycle.

[2] Geosits, R. F. and Y. Mohammad-zadeh, "Optimization of Air and Heat Integration for IGCC Plants", presented at Power-Gen Americas '95, Anaheim, CA, December 7, 1995.

Global Energy's two-stage gasifier at Wabash River has a relatively high cold gas efficiency of almost 77% when operating on either subituminous coal or petroleum coke. Carbon conversion efficiency is about 99%. When combined with high temperature heat recovery, heat integration, and steam extraction for process and gas turbine diluent use, high plant thermal efficiencies of 40% or greater can be achieved.

Because of the various stream interactions between the different sections in the plant, there are numerous opportunities for improving the heat integration and to increase the thermal efficiency. The Value Improving Practices exercise generated numerous Value Engineering ideas in this area. However, the objective of this study was to lower the cost of electricity and not to design plants with the highest thermal efficiency at any cost. Thus, economic viability provided the criteria for incorporating improvements. Depending upon the relative costs of fuel, products and equipment, the optimal plant thermal efficiency can change. Fir example, a plant using a low cost feedstock, such as coke, may have a better return on investment at a lower thermal efficiency than one that uses a high priced coal feedstock.

Table III.2 shows the basic heat and material balance equations and equations for calculating the plant output and overall efficiency. Detailed overall and process block heat and material balances were developed to predict plant performance (available under Global/Bechtel/Nexant secrecy agreement). However, the subtask report and the block flow diagram for each case, along with this summary report, contains sufficient data to check the overall heat balance and the carbon, sulfur and ash balances for each case.

It is apparent from these equations that the thermal efficiency (or heat rate) of an IGCC plant depends on the gasifier cold gas efficiency, combined cycle efficiency, high pressure steam cycle efficiency, and steam bottom cycle efficiency. Component efficiency is a function of the design and capital expenditures. All technologies asymptotically approach a thermodynamic limit as capital expenditures and operating and maintenance costs increase. Mature technologies are well optimized and have limited variability.

Global Energy's gasification technology appears to have some design flexibility (e.g., the Wabash River design vs. full slurry quench (FSQ) vs. full slurry vaporization (FSV)). In the Wabash River design, temperature control at the second stage outlet is maintained by injection of cooler syngas. With full slurry quench, the slurry feed is distributed between the first and second stages with the amount entering the second stage being manipulated to control the second stage outlet temperature. Wabash River is moving to this type of operation. With full slurry feed vaporization, the temperature control criterion is eliminated and all the fresh feed enters the second stage. Slurry feed vaporization theoretically provides the maximum conversion of feed to chemical energy and the lowest oxygen demand (ton O_2/ton feed), resulting in the highest cold gas efficiency.

Fuel cost per unit of production is inversely proportional to the efficiency except for the coke cases in this study where the coke is assumed to have a net zero cost. More importantly, increasing the cold gas efficiency will shift energy to the combined cycle section which will hopefully increase the power output (and efficiency).

III.4 Cost Drivers

The primary objective of this study was to reduce the cost of power from IGCC power plants and/or increase their return on investment. The following items were identified as the most important cost drivers.

1. Total Installed Cost
2. Plant and/or Train Size
3. Revenue Generating Capacity (Availability)
4. Operating and Maintenance Costs
5. Economic and Financial Environment
6. Project Specific Requirements

The plant designers can have an influence over the first four of the above cost drivers within technological limits. The fifth item, the economic and financial environment, is the ballpark in which the designers must work. It is an environment that is ever changing. It also depends on project specific requirements. For example, a natural gas fired combined cycle power plant will look good when natural gas prices are low, but when they shot up high in late 2000, many gas fired power plants would have shut down if they could because the revenue generated by their power sales was less that the cost of the natural gas used to produce it. For this reason, any contemplated project should be evaluated under the present and various likely future economic environments to determine if it is viable.

The total installed cost is the predominant cost driver over which the plant designer has the control. It also is the one over which he has the most control. For this reason, this study concentrated on reducing the plant cost. The Value Improving Practices procedures that were used in this study of Process Simplification (PS), Classes of Plant Quality (CPQ), Design-to-Capacity (DTC), Plant Layout Optimization (PL), Constructability Reviews (C), and Technology Selection (TS) all are related to reducing the total installed cost of the plant. Application of the above procedures resulted in the

1. Elimination of the redundant and/or duplicate equipment, such as unnecessary spare pumps (PS)
2. Reduction in the size of equipment by eliminating spare capacity or extra capacity for possible expansion (DTC)
3. Removal of things that would be “nice to have” but are not required (CPQ)
4. Deleting unnecessary flexibility by removing extra capacity in some plant sections in case a different feedstock may be used (CPQ)
5. Shrinkage in the plant site without sacrificing accessibility during construction or for maintenance to save piping and site preparation costs (PL)
6. Selection of the most cost effective technology (TS)
7. Improved scheduling for shorter construction times (C)
8. Increased output or increased efficiency

The main focus of the above VIPs was cost reduction and optimization with considerations given to the costs of cold gas efficiency improvements and additional heat recovery.

By application of the above procedures, significant cost reductions were achieved, and it is expected that more cost reductions will be achieved in the future. Operating and maintenance impacts also were considered. Table III.3 shows the approximate cost savings for the Subtask 1.3 Next Plant compared to the non-optimized Subtask 1.2 plant. Cost savings for specific items are documented in a confidential VIP report. A large amount of savings was found in the bulk materials through layout optimization, and by minimizing equipment costs by redesign and obtaining current quotes. Cost savings were also realized by eliminating costly equipment items, such as the slurry preheat exchangers, and by using extraction steam (similar to cogeneration) for diluent in the gas turbine. ASU integration did not show any economic benefit as the gas turbine should allow full flat rated output up to 80/90^{o}F ambient temperatures, and inlet air evaporative coolers can be used at higher ambient temperatures.

Increased output or increased efficiency was obtained by using slurry feed vaporization (SFV) or full slurry vaporization (FSV) which increases the cold gas efficiency, using extraction steam from the steam turbine as gas turbine diluent, and reducing the auxiliary power consumption of the air separation unit.

Cost reductions per unit of material processed can be achieved by using larger train sizes until the maximum size of a critical (or expensive) piece of equipment is reached. Generally equipment costs increase by the 0.6 to 0.7 power of the capacity. This means that the plant cost on a unit of material processed basis decreases as the plant size increases; i. e., the economies of scale effect. Because of this, all the current power and coproduction plants are sized to fully load the larger 210 MW GE 7FA+e combustion turbine. The Subtask 1.4 plant is sized to fully load the still larger future “H class” combustion turbine which is about 50% larger than the turbine used at Wabash River.

A plant that is shut down is not producing any revenue. Therefore, care was taken in the plant designs to minimize the amount of scheduled downtime, to increase reliability, and to facilitate maintenance access. Availability analyses based on operating data from the Wabash River Repowering Project which were used to predict the availability of the plant designs. For Subtask 1.3, three alternate design cases were evaluated by a discounted cash flow financial analysis based on revenue streams predicted by availability analyses to determine their expected required minimum power selling prices to generate a given ROI. This analysis showed that the extra revenue generated by the increased availability of a spare train outweighed its additional cost and was beneficial.

Any operating and maintenance (O&M) cost reductions fall directly to the bottom line. Although the specific details are considered proprietary, Global Energy personnel were included as part of the VIP team to develop and examine specific ideas for reducing the O&M costs of any new facility. If they were economic, the design changes were implemented, as required, to generate long term O&M savings. As a result of this effort, significant O&M savings based on Wabash River operations were achieved.

III.5 Plant Size

For IGCC plants, the capital cost is the largest component of the electricity cost. Table 13 on page 75 of the EIA *Annual Energy Outlook 2001* estimates the cost of producing electricity from an advanced coal plant of conventional design with a 36.9% thermal efficiency at 43.2 $/MW-hr.[3] About 72% of this cost is attributable to the capital cost of the plant, about 18% to the fuel cost, and about 10% to the operating and maintenance costs. This clearly shows that the plant cost is the dominant factor, and must be decreased in order to significantly reduce the cost of electricity. At the moment, IGCC plants are more

[3] U. S. Department of Energy, Energy Information Administration, “Annual Energy Outlook 2001 with Projections to 2020,” December 2000, www.eia.doe.gov/oiaf/aeo.

expensive on a per unit of export power than conventional pulverized coal power plants, but they have a higher efficiency. Thus, the capital cost component of the electricity cost is larger for IGCC plants.

As noted above, the cost of production decreases as the plant size increases. The general relationship between capacity and plant cost is that the plant cost increases with the capacity raised to the 0.6 to 0.7 power. This relationship holds until the maximum size of a critical or expensive piece of equipment is reached, and any further capacity increases only can be achieved by replicating that piece of equipment.

The costs of utilities and off site facilities also follow the same exponential relationship. The cost of production from multiple train plants also is lower than that from single train plants because the costs of the utilities and offsite facilities can be shared between trains. However, the reduction is not as great because the utilities and offsite facilities are not the major component of the plant cost.

Based on the above logic, the gasifier capacity would be expanded by up to 40% to 50% to take advantage of the economies of scale whenever it was appropriate since Global Energy believes this can be accomplished with their current design. Table III.4 shows the scaleup ratios of the major equipment in the gasification block. Except for the gasification reactor, the scaleup ratios for the other equipment is within commercial experience or easily obtainable. The 1.4 scaleup ratio for the air separation unit is within commercial experience. The Subtask 1.3 Next Plant Case uses two air separation units of just under 3,000 tpd, and new plants are being built with capacities of up to 3,500 tpd.

III.6 Study Perceptions and Strategic Marketing Considerations

This study is directed at a large audience which has many viewpoints, expectations and objectives. The study results are presented in a format that addresses these perceptions and strategic marketing considerations. If an in depth evaluation of any specific project or projects are required, a gasification technology vendor, such as Global Energy, should be contacted. The following is a list what we believe to be our readers major points of interest.

Promotion (or Planning Studies) – This report basically describes what is a series of planning studies for various coal and coke fueled IGCC applications. General economics were developed using a discounted cash flow model. These general results should allow prospective IGCC project developers to consider the merits of further evaluations of IGCC technology on a project specific basis.

Precision – Using cost information from the as-built Wabash River facility and Bechtel's Power Line™ plants allowed the cost estimates to have a high degree of confidence or, expressed differently, a minimum amount of uncertainity.

Potential – This study addresses the potential of Global Energy's gasification technology to reduce the cost and improve the efficiency of IGCC plants. Further cost savings have been identified, but not yet quantified. These items are being investigated.

Price – The above mentioned cost savings significantly reduced the cost of electricity to the point where under certain situations IGCC is competitive.

Product (or Market Penetration) – Currently coke fueled IGCC plants have the advantage over coal fueled ones because of the lower feedstock cost. The initial application of coke IGCC plants will further develop IGCC technology leading to improved designs, reduced costs, and increased efficiencies.

Place (Location) – The U. S. Gulf coast location, especially if it is on a waterway, seems to be the best location for coke fueled IGCC plants because it is likely close to the source of the refineries that produce the coke. A coke coproduction plant should be located adjacent to a petroleum refinery to minimize transportation costs and allow sharing of support facilities.

Proliferation - As more IGCC plants are built using either coke and coal. Their costs will decrease leading to the construction of additional IGCC plants.

Preferred Design – The Subtask 1.3 Next Plant is the preferred design for a coke IGCC coproduction plant and includes a two-stage dry particulate removal system. However, during the study wet particulate filtration tests showed better than expected results. Therefore, Global Energy also is considering pursuing the development of a wet filtration system to determine if additional cost savings are possible. In any case, as capital costs continue to decrease and fuel prices increase, large coal fueled IGCC facilities, similar to the Subtask 1.6 case, will become the preferred design for coal power plants.

Promise – IGCC plants have higher efficiencies than pulverized coal facilities with the potential of further increased efficiencies coupled with lower costs. The potential of very low SO_2 and NOx emissions coupled with CO_2 capture are possible in the near future.

Promote – This study promotes the development and implementation of IGCC by demonstrating that starting with the Wabash River design and applying VIP optimization techniques, it is possible to build a low cost IGCC plant that produces electricity at competitive prices.

Prospectus – IGCC project development requires detailed analysis and planning on a project specific basis. Study performance may not be indicative of or adequately quantify future revenues.

Table III.1

Task 1 Coal and Coke IGCC Case Summaries

Case	Subtask 1.1	Subtask 1.2	Subtask 1.3				Subtask 1.4	Subtask 1.5		Subtask 1.6	Subtask 1.7
Description	Wabash River Greenfield	Petroleum Coke IGCC Coproduction	Optimized Petroleum Coke IGCC Coproduction Plant Base Case	Min Cost	Spare Train	Next Plant	Optimized Coal to Power IGCC	Single Train Power 1.5A Coal	1.5B Coke	1,000 MW Coal IGCC Power Plant	Coal to Hydrogen
Configuration											
Plant Location	Midwest	Gulf Coast	Gulf Coast	Gulf Coast	Gulf Coast	Gulf Coast	Midwest	Gulf Coast	Gulf Coast	Midwest	Midwest
Number of Air Separation Units	1	2	2	2	2	2	1	1	1	3	1
Number of Gas Turbines	1	2	2	2	2	2	1	1	1	4	0
Number of Gasification Trains	1	3	2	2	3	3	1	1	1	4	1
Number of Gasification Vessels	2	3	4	2	3	3	1	2	2	4	2
No of Syngas Processing Trains	1	3	2	2	2	2	1	1	1	2	1
Number of 50% H2 trains	NA	3	2	2	2	2	NA	NA	NA	NA	2
Design Feed Rates											
Feedstock Type	Coal	Pet Coke	Pet Coke	Pet Coke	Pet Coke	Pet Coke	Coal	Coal	Pet Coke	Coal	Coal
Coal or Coke, TPD as received	2,642	5,515	5,679	5,679	5,679	5,692	3,517	2,754	2,077	10,837	3,517
Coal or Coke, TPD dry	2,259	5,249	5,399	5,399	5,399	5,417	3,007	2,355	1,977	9,266	3,007
Feed, MMBtu HHV/hr	2,400	6,495	6,680	6,680	6,680	6,703	3,195	2,481	2,446	9,844	3,195
Feed, MMBtu LHV/hr	2,311	6,364	6,545	6,545	6,545	6,567	3,076	2,389	2,397	9,478	3,076
Flux, TPD	0	107	110.2	110.2	110.2	110.6	0	0	40.3	0	0
Water, gpm	2,790	4,830	5,146	5,146	5,146	5,146	3,079	2,840	2,525	9,752	2,457
Condensate, Mlb/hr	---	686	686	686	686	686	---	---	---	---	---
Oxygen, TPD of 95% O2	2,130	5,962	5,917	5,917	5,917	5,954	2,294	2,015	2,143	8,009	2,522 (99.5%)
Oxygen, TPD of O2	2,009	5,622	5,580	5,580	5,580	5,615	2,164	1,900	2,021	7,553	2,507
Design Product Rates											
Electric Power, MW	269.3	395.8	460.7	460.7	460.7	474.0	416.5	284.6	291.3	1,154.6	-18.4
Steam (750°F/700 psig), lb/hr	---	980.0	980.0	980.0	980.0	980.0	---	---	---	---	---
Hydrogen, MMscfd	---	79.4	80.0	80.0	80.0	80.0	---	---	---	---	141.2
Sulfur, TPD	57	367	372	372	372	373	77	60	136	237	76
Slag (@ 15% water), TPD	356	190	195	195	195	195	462	364	71	1,423	474
Fuel Gas, MMBtu HHV/hr	---	363	0	0	0	0	---	---	---	---	---
Solid Waste to Disposal, TPD	---	---	---	---	---	---	3.0	---	---	---	---
Gas Turbine											
Type	GE 7FA	GE 7FA	GE 7FA+e	GE 7FA+e	GE 7FA+e	GE 7FA+e	"G/H-class"	GE 7FA+e	GE 7FA+e	GE 7FA+e	NA
Fuel Input, Mlb/hr	411.4	861.9	984.6	984.6	984.6	1,016.8	543.8	447.0	426.7	1,741.6	---
Heat Input, MMBtu/hr LHV	1,675	3,374	3,580	3,580	3,580	3,592	2,427	1,796	1,796	7,184	---
Steam Injection, Mlb/hr	111.0	164.2	429.1	429.1	429.1	395.7	620.1 of N2	246.8	272.3	1,037.8	---
Gross Power Output, MW	192	384	420	420	420	420	300	210	210	840	---
Cold Gas Efficiency (HHV), %	76.9	76.9	77.4	77.4	77.4	77.5	80.8	77.8	77.4	78.0	76.5
Steam Turbine Power, MW	118	118.8	150	150	150	164.3	164.1	113	121	465.2	70.6
Internal Power Use, MW	41	107	109	109	109	110	48	38.4	40.7	151	89.0
Heat Rate, Btu/kW-hr	8,912	NA	NA	NA	NA	NA	7,671	8,717	8,397	8,526	---
Thermal Efficiency, % HHV	38.3	NA	NA	NA	NA	NA	44.5	39.1	40.6	40.0	---
Emissions											
SOx as SO2, lb/hr	312	306	385	385	385	350	37	142	119	438	191
NOx as NO2, lb/hr	161	325	166	166	166	166	127	69	69	275	27
CO, lb/hr	56	111	105	105	105	106	47	41	41	161	1,846
Sulfur Removal, %	96.7	99.5	99.4	99.4	99.4	99.4	99.7	98.5	99.4	98.9	98.5
Performance Parameters											
Tons 02 / Ton of Dry Feed	0.889	1.071	1.034	1.034	1.034	1.037	0.720	0.807	1.022	0.815	0.834
Gross MW / Ton of Dry Feed	0.137	0.096	0.106	0.106	0.106	0.108	0.154	0.137	0.168	0.141	---
Net MW / Ton of Dry Feed	0.119	0.075	0.085	0.085	0.085	0.088	0.139	0.121	0.147	0.125	---
Emissions											
SOx (SO2) as lb/hr-MW	1.159	0.773	0.836	0.836	0.836	0.738	0.089	0.499	0.409	0.379	---
NOx (NO2) as lb/hr-MW	0.598	0.821	0.360	0.360	0.360	0.350	0.305	0.242	0.237	0.238	---
CO, lb/hr-MW	0.208	0.280	0.228	0.228	0.228	0.224	0.113	0.144	0.141	0.139	---
Daily Average Feed/Product Rates with Backup Natural Gas (Subtasks 1.1 and 1.7 are without Backup Natural Gas)											
Coal or Coke, TPD dry	1,705	4,635	4,310	3,973	4,814	4,842	2,400	1,826	1,546	7,018	2,470
Coal or Coke, % of design	75.5%	88.3%	79.8%	73.6%	89.2%	89.4%	79.8%	77.5%	78.2%	75.7%	82.2%
Power, MW	203.2	374.3	430.0	425.4	436.4	448.4	387.8	264.4	269.4	1,081	---
Power, % of design	75.5%	94.6%	93.3%	92.3%	94.7%	94.6%	93.1%	92.9%	92.5%	93.6%	---
Steam, lbs/hr	---	972.2	958.6	946.2	974.1	974.6	---	---	---	---	---
Steam, % of design	---	99.2%	97.8%	96.6%	99.4%	99.4%	---	---	---	---	---
Hydrogen, MMscfd	---	78.8	77.5	76.5	78.7	78.8	---	---	---	---	116.7
Hydrogen, % of design	---	99.2%	97.8%	96.6%	99.4%	99.4%	---	---	---	---	81.3%
Fuel Gas, MMBtu HHV/hr	---	360.1	0	0	0	0	---	---	---	---	---
Fuel Gas, % of design	---	99.2%	---	---	---	---	---	---	---	---	---
Natural Gas, Mscfd	NA	10,099	20,000	26,977	9,303	9,059	8,896	6,929	6,929	34,960	NA
Plant Cost, MM mid-2000 $[1]	452.6	993.2	764.0	746.0	812.6	787.3	464.7	375.0	367.0	1231.3	529.8
Plant Cost, $/design kW	1,681	NA	NA	NA	NA	NA	1,116	1,318	1,260	1,066	---
Required Electricity Selling Price for a 12% ROI, $/MW-hr[2]											
Without Natural Gas Backup	67.5	---	---	---	---	---	42.8	53.9	43.9	44.4	NA
With Natural Gas Backup	---	43.4	34.4	36.5	32.5	30.0	39.8	48.9	40.6	40.2	NA

NA = Not Applicable
January 8, 2002

1. All costs are mid-year 2000 EPC costs which exclude contingency, taxes, fees and owners costs. They are presented here to show the relative differences between cases. Current cost estimates should be developed for any proposed applications.
2. Power selling prices are presented to show a relative comparison between cases. The use of natural gas backup is described in Section II.4.2.

Table III.2
Basic Plant Energy Balance and Efficiency Equations

Energy Balance Equations

For the Entire IGCC Plant
Q(In) = Q(Out)
Q(In) = Q(fuel energy) + Q(auxiliary power) + Q(air sensible heat)
Q(Out) = Energy in Products and Byproducts + Q(cooling tower) + Q(stacks) + Q(losses)

where the Energy in Products and Byproducts includes the power, hydrogen, steam, sulfur, and slag

For the Gasification Area
Q(In) = Q(Out)
Q(In) = Q(fuel energy) + Q(auxiliary power) + Q(air sensible heat)
Q(Out) = Q(syngas gas turbine fuel) + Q(sensible and latent heat in the syngas) +
Q(high pressure steam) + Q(sulfur) + Q(carbon in slag) + Q(incinerator stack) +
Q(hydrogen) + Q(cooling tower) + Q(excess) + Q(losses)

where Q(excess) is the net excess of all other energy transferred between areas

For the Combined Cycle Area
Q(In) = Q(Out)
Q(In) = Q(syngas gas turbine) + Q(sensible and latent heat in the syngas) +
Q(high pressure steam) + Q(excess) + Q(auxiliary power) + Q(air)
Q(Out) = Q(power) + Q(stack) + Q(cooling tower) + Q(losses) + Q(export steam)

Note: Similar equations may be developed for the overall mass balance and for ash/slag, carbon, and sulfur.

Efficiency Equations

Overall Efficiency = Energy In Useful Products / Energy In Fuel
Overall Efficiency = [Energy to Combined Cycle x {Combined Cycle Efficiency}
+ Energy in High Pressure Steam x Steam Cycle Efficiency
+ Low Level Energy x {Bottoming Cycle Efficiency}
+ Energy in Products and Byproducts
- Auxiliary Power] / [Fuel Energy]

Where: Energy to Combined Cycle =[Syngas Gas Turbine Fuel + Syngas Sensible Heat]
Combined Cycle Efficiency = 55 to 60% (LHV basis)
Steam Cycle Efficiency = ~35 to 40%
Bottoming Cycle Efficiency < 33%

For the IGCC cases without coproduction:
(Fuel Energy) x (Syngas Cold Gas Efficiency) = Syngas Gas Turbine Fuel

Refer to General Electric data for gas turbine performance and the BFD for integration of the streams.

Notes:
1. All heat values are higher heating values, HHV
2. Carbon conversion is 99%
3. The syngas cold gas efficiency and syngas gas turbine fuel are given for each case in Table III.1

Table III.3

VIP Modifications and Associated Cost Savings* for the Subtask 1.3 Next Plant Compared to the Subtask 1.2 Plant

Value Improving Practice	Description	Approximate Gasification Area Cost Savings
Process Simplification	Simplified Feed System Removed Slurry Heaters and Spare Pumps	~20 MM$
	Removed Post Reactor Vessels and New Advanced Solids Removal System	~15 MM$
Powerline Design	Increased Output	Same Cost
Optimized Layout	Reduced Bulk Piping, Electrical Material, etc. and Installation Labor	~100 MMS
Availability Analysis	Minimized Number of Trains and Spare Units	~70 MM$
Total		~ 205 MM$

* The savings primarily are in the combined gasification and balance of plant areas.

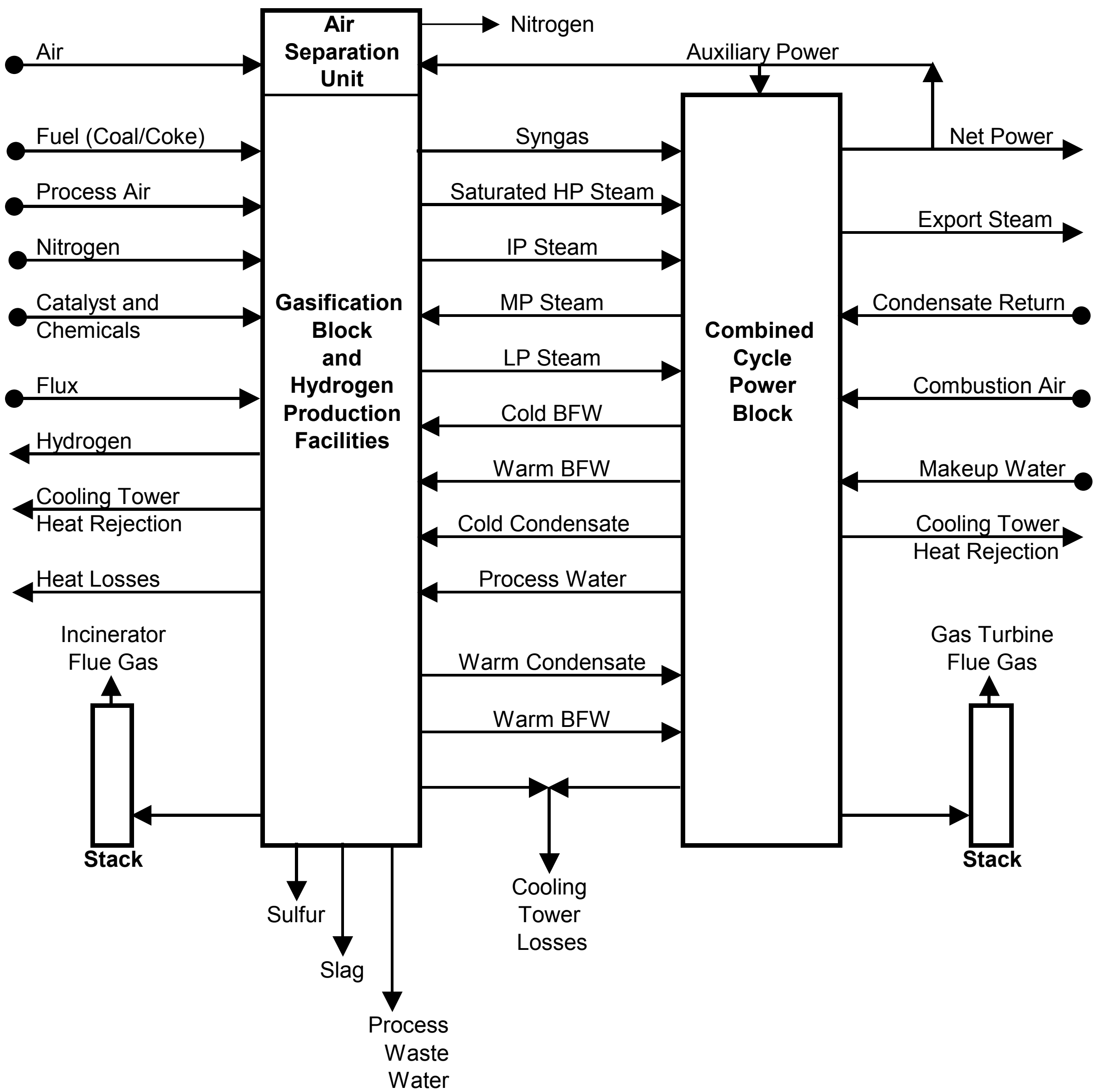
Table III.4

Scaleup Ratios of the Gasification Plant Sections

Case Description	Subtask 1.1 Wabash River Greenfield	Subtask 1.2 Petroleum Coke IGCC Coproduction	Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant Base Case	Subtask 1.3 Min Cost	Subtask 1.3 Spare Train	Subtask 1.3 Next Plant	Subtask 1.4 Optimized Coal to Power IGCC	Subtask 1.5 Single Train Power 1.5A Coal	Subtask 1.5 Single Train Power 1.5B Coke	Subtask 1.6 1,000 MW Coal IGCC Power Plant	Subtask 1.7 Coal to Hydrogen
Rod Mills	Base	1.0	1.7	1.7	1.7	1.7	1.3	1.0	0.8	1.0	1.1
Gasifier	Base	1.4	1.4	1.4	1.4	1.4	1.4	1.0	1.0	1.0	1.3
HTHR Boiler	Base	1.3	1.7	1.7	1.7	1.6	0.7	0.9	1.0	0.9	0.7
Low Temperature Cooler	Base	1.4	1.4	1.4	1.4	1.4	1.4	1.0	1.0	1.0	1.3
Acid Gas Removal	Base	1.5	1.5	1.5	1.5	1.6	0.6	0.5	1.1	1.0	0.6
Sulfur Recovery Unit	Base	1.5	1.5	1.5	1.5	1.6	0.6	0.5	1.1	1.0	0.6
Air Separation Unit	Base	1.4	1.4	1.4	1.4	1.4	1.1	0.9	1.0	1.3	1.2

Figure III.1

Interconnecting Streams for the Subtask 1.3 Next Plant



Chapter IV

Petroleum Coke Cases

Current IGCC market opportunities (based on recent proposal requests) are large multi-train, multi-product coke IGCC coproduction plants and large mine-mouth coal IGCC plants. This chapter describes five petroleum coke IGCC coproduction plants and one petroleum coke IGCC power plant.

Six petroleum coke IGCC plant cases were developed. Five were coproduction plant designs, which produced hydrogen and steam for an adjacent petroleum refinery, and one was a single-train petroleum coke IGCC power plant. The design basis for the coproduction plants was based upon a typical refinery project (hypothetical) which will process about 5,300 TPD of dry petroleum coke and produce 80 MMscfd of 99% hydrogen at 1,000 psig and 980,000 lb/hr of 750°F/700 psig steam while maximizing the export power production from two General Electric 7FA combustion turbines. Condensate, amounting to about 70% of the exported steam, is returned from the refinery to the gasification plant. The coke feed rate is set so as to fully load the gas turbines.

Besides coal, petroleum coke was chosen as the feedstock for the gasification plant because the IGCC concept is commercially ready and economically viable for the current refining market. Various plant configurations were investigated and presented in this report so that potential technology users may evaluate the applicability of petroleum coke IGCC technology for their specific situations.

IV.1 The Petroleum Coke IGCC Coproduction Plants

The size of the petroleum coke IGCC coproduction plant was set by the hydrogen production and reliability requirements with the hydrogen capacity being set based on the size of a typical steam methane reforming (SMR) system of about 80 MMscfd. Hydrogen availability was assumed to be greater than 98% to match SMR performance and refinery needs. Therefore, at least one spare gasification train is required for continuous hydrogen production, and one or more gasification trains with larger coke capacities are required for power production. Furthermore the design should allow turn down or operation with backup natural gas for power production, if necessary, and include a spare train to minimize power purchases and improve project economics.

The objectives of the petroleum coke IGCC coproduction cases were to (1) develop a non-optimized, highly reliable petroleum coke-based IGCC coproduction plant design (Subtask 1.2) based on the Wabash River coal IGCC demonstration plant configuration, (2) develop an optimized petroleum coke IGCC coproduction plant design (Subtask 1.3 and Subtask 1.3 Next Plant), and (3) illustrate how the optimized IGCC coproduction plant configuration may enhance overall project profitability. Four optimized Subtask 1.3 design variations were developed leading to the Subtask 1.3 Next Plant design which although is not the least costly design, it is the most efficient, least polluting, and has the highest return on investment.

Because the gasification plants are attached to a petroleum refinery, they, in effect, become a part of that refinery, and therefore, the export hydrogen and steam streams must be very reliable (have reliabilities greater than 98%). Any unscheduled loss of either the hydrogen or steam streams could have a catastrophic effect on the refinery operations forcing numerous unit shutdowns and resulting in significant revenue losses. Thus, special plant configuration and plant operating procedure are incorporated to maintain the required on-stream factor for the production of process steam and hydrogen.

The Subtask 1.2 case is an enlarged, three-train, non-optimized modification of the Subtask 1.1 Wabash River Greenfield Plant to process petroleum coke at a Gulf Coast location with the addition of the hydrogen and steam generation facilities. This design was developed with three gasification trains (two operating and one spare) feeding two parallel General Electric 7FA combustion turbines. Figure IV.1 is a simplified block flow diagram of the Subtask 1.2 plant. These gas turbines are the same as the one that is installed at Wabash River. In the event of an outage of one gasification train, the spare train can be put on-line to provide the design hydrogen and steam rates to the refinery without sacrificing export power production. The low BTU PSA tail (sweep) gas is sent to the refinery for fuel gas. The Subtask 1.2 plant processes 5,249 TPD (dry basis) of petroleum coke and produces 79.4 MMscfd of 99% hydrogen, 980,000 lb/hr of 750^{o}F/700 psig steam, 363 MMBtu/hr (HHV) of fuel gas, and 395.8 MW of export power. Condensate, amounting to about 70% of the exported steam, is returned from the refinery to the gasification plant. The Subtask 1.2 case is described in greater detail in Appendix B.

There are four design variations of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant: (1) Subtask 1.3 Base Case, (2) Subtask 1.3 Minimum Cost Case, (3) Subtask 1.3 Spare Gasification Train Case, and (4) Subtask 1.3 Next Optimized Plant Case. The first three designs use a low cost dry/wet particulate removal system and differ only in the amount of spare and replicated equipment that they contain. The purpose of developing and documenting these three cases was to determine the effect of replicated equipment on availability and its cost benefit (Appendix C). The fourth, the Subtask 1.3 Next Optimized Plant Case was developed based on the spare gasification train case (Appendix D). The Subtask 1.3 Next Plant contains an improved dry particulate removal system and other improvements. Figure IV.2 is a simplified block flow diagram of the Subtask 1.3 Next Plant. All Subtask 1.3 plants use the newer, larger, and more efficient General Electric 7FA+e combustion turbine (210 MW capacity) rather than the older 7FA model (192 MW capacity) used in Subtask 1.2. Table IV.1 summarizes the plant performance, plant capital costs, and the required power selling prices at 12% after-tax ROI of the Subtask 1.2 and 1.3 Petroleum Coke IGCC Coproduction Plants.

In all of the Subtask 1.3 designs, higher steam injection rates were used to reduce the thermal NOx emissions and to increase the power production than are used at Wabash River or in the Subtask 1.2. Attachment A shows the performance of the General Electric 7FA+e gas turbine which was provided by General Electric.

The Subtask 1.3 Next Plant is the preferred case of the four Subtask 1.3 designs because it requires the lowest electricity selling price for a 12% ROI ($30/MW-hr). This case includes a spare gasification train from the feed pumps through the particulate removal section with minimal sparing elsewhere. The particulates are removed from the syngas in a completely dry two-step process; first a cyclone removes over 90% of the solids and then dry char filters (instead of a wet scrubber as used in the other Subtask 1.3 cases) remove the remainder. This particulate removal system is cheaper than the wet scrubber system used in the other Subtask 1.3 cases and the dry char filter system used at Wabash River. It should have a higher availability. Also, the coke feed rate and export power production are increased by about 3%. Furthermore, the spare wet scrubber column was eliminated. Appendix D contains a detailed description of the Subtask 1.3 Next Plant design as well as a discussion covering the availability and financial analyses that were performed to evaluate the Subtask 1.3 cases.

Figure IV.3 is a block flow diagram of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant. It also shows the major stream flow rates. Figure IV.4 is a site plan for the Subtask 1.3 Next Plant, and Figure IV.5 is an artists' conception of the facility.

The first three Subtask 1.3 designs all have the same process flow scheme and process 5,399 tpd (dry basis) of petroleum coke and produce 80 MMscfd of 99% hydrogen, 980,000 lb/hr of 750^{o}F/700 psig steam, and 460.7 MW of export power. PSA hydrogen recovery is 85%. In all three cases, the gasification plant differs from the Wabash River design in that the particulates are removed from the syngas in a two-step process; first a cyclone removes over 90% of the solids, and then a wet scrubber removes the remainder. These three cases were developed in order to examine the amount of replication and spare equipment on the plant cost, expected performance (availability), and economics. Furthermore, they provided a springboard for development of an improved solids removal system with higher availability which is used in the Subtask 1.3 Next Plant design.

The Subtask 1.3 Base Case design contains two parallel gasification trains with each gasification train containing a spare gasification vessel. This is the Wabash River gasification reactor configuration. It is described in detail in Appendix C. When it is necessary to replace the refractory in one gasifier, the piping can be switched (via swing spool pieces) to place the spare vessel in service and minimize the downtime. Thus, the time-consuming refractory replacement can be done while the plant is operating.

The Subtask 1.3 Minimum Cost case is identical to the Base Case except that the spare gasification vessels have been removed from each gasification train. This case was developed to determine if the cost savings would compensate for the lost revenue that occurs during the long outages when the train is shutdown for refractory replacement.

The Subtask 1.3 Spare Gasification Train Case added a complete spare gasification train from the slurry feed pumps through the wet scrubber. Thus, when one of the operating trains has to be shut down either for maintenance or problems, the spare train can be brought on line and production can be maintained. This case was developed to determine if the extra revenue from the increased production could compensate for the additional cost of the spare train.

An availability analysis of each of the cases was performed based on the EPRI recommended procedure using the Wabash River availability data.[1,2] Table IV.1 and Figure IV.6 show the design and calculated daily average flow rates for the Subtask 1.2 and the four 1.3 plants. These results showed that the Subtask 1.3 Next Plant has the highest availabilities and the highest daily average product rates. Appendix J contains a complete description of the availability analyses studies that were performed.

[1] Research Report AP-4216, "Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems", Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304, August 1985.
[2] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.

The “overnight” mid-year 2000 EPC costs for the Subtask 1.2 and 1.3 petroleum coke IGCC coproduction plants also are shown in Table IV.1. The Subtask 1.2 plant cost is 993.2 MM$. The four Subtask 1.3 plant costs range from 812.6 MM$ to 746.0 MM$. As compared to the cost of the four non-optimized Subtask 1.2 case, the saving varies from 180.6 MM$ to 247.2 MM$. These savings are the result of the Value Improving Practices and optimization efforts.

Chapter II presented the basic economic parameters that were used for all the financial analyses in this study for determining the return on investment (ROI). The prices are based on long-term projections for the U. S. Gulf Coast (except the coal price which is a Mid-West price). The inflation rates generally are based on the Energy Information Administration’s *Annual Energy Outlook 2001.*[3] Using a discounted cash flow economic model that was developed by Nexant, Inc. for the Department of Energy, the required power selling prices that were required to produce a 12% after tax ROI were calculated.[4] The bottom row of Table IV.1 shows the results. In all cases, backup natural gas is used to fire the combustion turbines whenever sufficient syngas is unavailable in order to provide export power.

The Subtask 1.2 plant requires a power selling price of 43.4 $/MW-hr. The required power selling prices for the Subtask 1.3 plants varies between 32.5 $/MW-hr for the Spare Train Case to 36.5 $/MW-hr for the Minimum Cost Case. The Minimum Cost Case has the highest power selling price showing that elimination of the spare gasification vessels is not advantageous. For the best Subtask 1.3 case, the Spare Train Case, the required selling price was reduced by almost 11 $/MW-hr as a result of this study. Furthermore, examination of the first three Subtask 1.3 cases shows that the extra cost of the spare train to increase the average daily plant capacity is beneficial since it reduces the required power selling price for a 12% ROI by about 2 $/MW-hr over the Base Case. See Appendix C for a more complete availability and financial analysis of the Subtask 1.3 plants.

As shown in Table IV.1, the further optimization made in the Subtask 1.3 Next Plant case reduced its cost to 787.2 MM$, or about 25 MM$ less than that of the Subtask 1.3 Spare Train Case. As a result, the required power selling price for a 12% ROI dropped to 30.0 $/MW-hr. This is a 30% reduction in the electricity price compared to the non-optimized Subtask 1.2 plant.

A advanced natural gas combined cycle plant starting up in 2005 is expected to have a heat rate of 6,639 HHV Btu/kw-hr (6,035 LHV Btu/kW-hr).[3] With 2.60 $/MMBtu HHV natural gas, this gas-fired power plant will require an export power price of 33.0 $/MW-hr to generate a 12% ROI. Thus, the Subtask 1.3 Next plant is competitive with a new natural gas combined cycle plant that will be starting up at about the same time.

Currently, the United States is in a period of low inflation and very low interest rates. With an 8% loan interest rate and the same 3% upfront financing fee, the required power selling price for the Next Plant drops to 28.6 $/MW-hr which is competitive with current power prices. As natural gas prices rise above the 2.60 $/MMBtu price assumed in this economic analysis, petroleum coke gasification plants should become even more competitive.

---

[3] U. S. Department of Energy, Energy Information Administration, “Annual Energy Outlook 2001 with Projections to 2020”, December 2000, www.eia.doe.gov/oiaf/aeo.

[4] Nexant Inc., “Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation”, Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

Figure IV.7 shows the effect of the power selling price on the return on investment for the Subtask 1.2, Subtask 1.3, and Subtask 1.3 Next Plant cases. At a 30.0 $/MW-hr the Subtask 1.3 Next Plant will produce a 12% ROI, which is over 2 points better than the Subtask 1.3 Spare Train Case and over 9 points better than the Subtask 1.2 plant. As the power selling price increases, the ROIs increase significantly. At a 35 $/MW-hr power selling price the Subtask 1.3 Next Plant has a 16.7% ROI, and at a 40 $/MW-hr, it has a ROI of 21.1%. With a 10% loan interest rate and a 30$/MW-hr power selling price, the ROIs for the Subtask 1.3 Next Plant and the Subtask 1.3 Spare Train case increase to 15.7% and 13.4%, respectively.

IV.2 The Single-Train Petroleum Coke IGCC Power Plant

The objective of Subtask 1.5 was to highlight the similarities and differences between single-train coal- and coke-fueled IGCC power plants located on the U. S. Gulf Coast. Both plant designs were developed from the original, but larger, optimized Subtask 1.3 Petroleum Coke IGCC Coproduction Plant. Appendix F provides a detailed discussion and comparison of these two plants. The results of this case show that there are sufficient similarities between the coal- and coke-fueled IGCC plants so that experience acquired from the design, construction, and operation of coke-fueled IGCC plants will reduce the technical risk, capital, and operating costs of coal-fueled IGCC plants.

Since its startup in 1994, Wabash River has been operating commercially on its design feedstock, high sulfur coal. Subsequently, the plant has been operating on delayed petroleum coke to reduce feedstock cost. Coke operations have been very smooth with minor changes from the coal operations.[5] This showed that a plant designed for coal can operate on petroleum coke and confirmed that the designs for both coal and coke plants are similar. When the plant was using coke:

- There were no operational problems.
- Less boiler fouling was observed.
- Tar in the syngas is negligible
- Additional char is produced, but it could be handled in the existing particle removal system
- Industrial hygiene considerations are the same as for coal operation.

In this study, the design to capacity (DTC) reviews for the coal and coke feedstocks were based on actual operating experience. Following is a brief list of the DTC adjustments that highlight the design differences between coal and coke:

- Coke is harder to grind and has a higher specific horsepower requirement than coal.
- The low moisture content of coke makes it easier to slurry and to achieve higher slurry concentrations. However, this is offset by the lower reactivity of coke so that coal has a slightly higher cold gas efficiency than coke.

[5] Amick, P., "Gasification of Petcoke using the E-GAS Technology at Wabash River," 2000 Gasification Technologies Conference, San Francisco CA, Oct. 8-11, 2000.

- Coke has a greater energy content per pound (HHV), because it contains less non-fuel components (i.e., nitrogen, oxygen, ash, and water). This, combined with higher slurry concentrations, reduces the capacity of the slurry feed system
- Coal has a slightly higher carbon conversion, but both feedstocks have high overall carbon conversions.
- The clean syngas compositions for coal and coke are shown in Table IV.2. The syngas compositions are similar, but the syngas from coke contains more CO and less H_2. Because of the higher slurry concentration, the coke-based syngas contains less CO_2.
- The higher carbon content and lower oxygen content of coke usually increases the oxygen requirements.
- Coke produces little or no tars. Therefore, the T-120 soak vessel is not required.
- Coke has very little ash, and requires flux addition to keep the molten ash flowing.
- The use of flux and char recycle keeps the nickel and vanadium in the slag, and out of the downstream gas systems.
- Coke has more than twice the sulfur content of coal. Therefore, larger acid gas removal systems, sulfur recovery units, and tail gas recycle compressors are required.

While individual process units change in size, the cost of the overall coal and coke IGCC systems are about the same. Furthermore, if a plant were designed for both/either feedstock, then many areas would have to be oversized (as is the case with Wabash River) making the plant more costly. Therefore, a clear single-point definition of the plant feedstock with minimum variation/range of composition is needed for development of a minimal cost design.

The Subtask 1.5B coke fueled IGCC power plant processes 1,977 TPD of delayed petroleum coke and produces 291.3 MW of export electric power, 136 TPD of sulfur, and 71 TPD of slag. It has a heat rate of 8,397 Btu/kW-hr and a thermal efficiency (HHV) of 40.64%. The total installed plant cost is 367 MM$ (mid-year 2000 $) or 1,261 $/kW.[6]

Based on the previously discussed economic parameters, the required power selling price for a 12% ROI is 43.9 $/MW-hr without the use of backup natural gas, and 40.6 $/MW-hr with the use of backup natural gas during periods when there is an outage of the gasification block. At an 8% loan interest rate, the required power selling price for a 12% ROI with natural gas backup drops to 37.8 $/MW. Both of these power prices are above those required by the advanced natural gas combined cycle plant.

The economics of the Subtask 1.5B Petroleum Coke IGCC Power Plant will be compared with the Subtask 1.5A Coal IGCC Power Plant in Section V.2 of this report where power only plants are discussed. This will allow a comparison with the other single-train IGCC power plants, all of which are coal fired, that were developed during this study.

At the Wabash River facility, Global Energy has been making significant gains in operating on both coal or coke, improving the technology, and reducing the O&M costs. As the owner/operator of the Wabash River gasification system, Global Energy has the ability to

[6] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

test new technology developments. This testing will support project financing and commercial development.

Currently there is a market for large petroleum coke IGCC coproduction plants because of the availability of low cost coke and the need for new hydrogen production capacity. Thus far, there are three operating petroleum coke gasification plants (Delaware Clean Energy Project, ExxonMobil Baytown Syngas Project, and Farmland Industries Petrochemical Plant.). Therefore, significant experience in the design, engineering, construction, and operation will be available before a coal-fueled IGCC plant is built. While it is difficult to quantify these benefits, the capital and operating costs of the coal-fueled IGCC plants shown in this report could be further reduced. The operating success of these coke-fueled IGCC plants also will reduce the technical risks associated with coal-fueled plants. Subsequently, project financing costs will be lowered because of the demonstrated commercial performance of these coke-fueled IGCC projects.

Table IV.1
Comparison of the Subtask 1.2 and 1.3 Cases

	Subtask 1.2		Subtask 1.3				Subtask 1.3 Next Plant	
				Daily Average				
Case	Design	Daily Average	Design	Base Case	Minimum Cost Case	Spare Train	Design	Daily Average
Product Rates								
Power, MW	395.8	374.3	460.7	430.0	425.4	436.4	474.0	448.4
Hydrogen, MMscfd	79.4	78.8	80.0	77.5	76.5	78.7	80.0	78.8
Steam, Mlb/hr	980.0	972.2	980.0	958.6	946.2	974.1	980.0	974.6
Sulfur, TPD	367.0	324.1	371.8	296.8	273.6	331.5	373.4	333.8
Slag, TPD	190.0	167.8	194.5	155.3	143.1	173.4	195.1	174.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0	0	0
Input Rates								
Coke, TPD	5,249	4,635	5,399	4,310	3,973	4,814	5,417	4,842
Flux, TPD	107	94.5	110.2	88.0	81.1	98.3	110.6	98.9
Natural Gas, MMBtu/d	0	10,099	0	20,000	26,977	9,303	0	9,059
EPC Cost (see note), MM$ (mid-year 2000)		993.2		764.0	746.0	812.6		787.2
Required Power Selling Price For a 12% after-tax ROI, $/MW-hr		43.36		34.45	36.49	32.48		30.02

Note:
All EPC plant costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Table IV.2

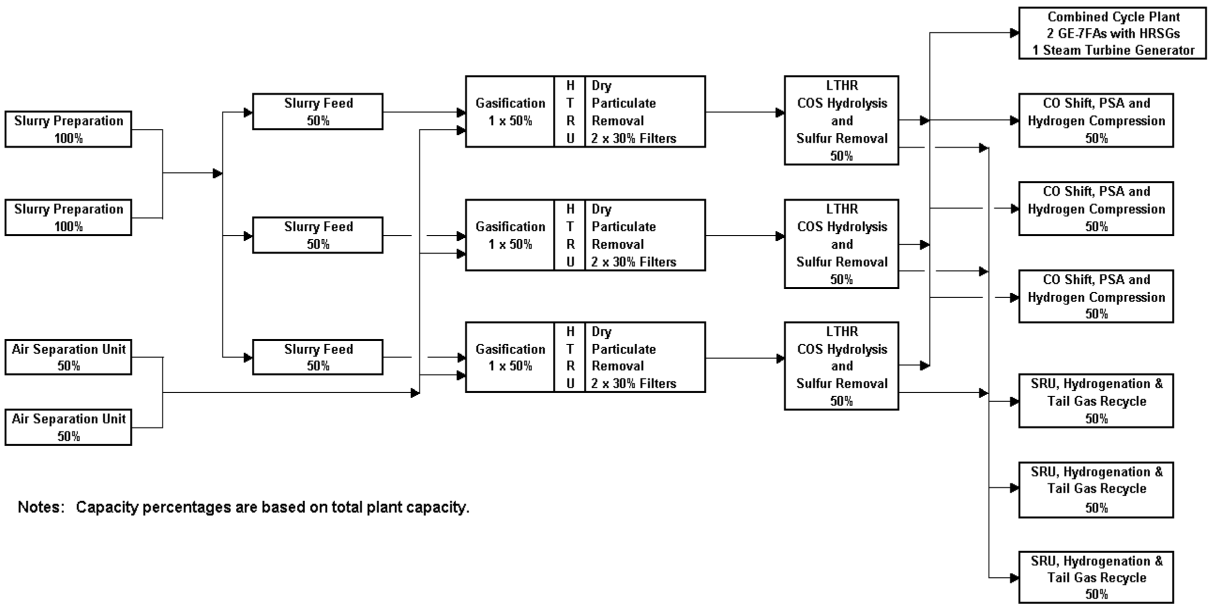
Comparison of Subtask 1.5 Coal and Coke Syngas Compositions

	Subtask 1.5A	Subtask 1.5B
Feedstock	Coal	Petroleum Coke
Syngas Composition, mole% dry		
Hydrogen	33.2	27.2
Carbon Monoxide	46.3	59.6
Carbon Dioxide	14.3	9.0
Methane	3.6	1.6
Other	2.6	2.6

Figure IV.1

Subtask 1.2 - Train Block Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

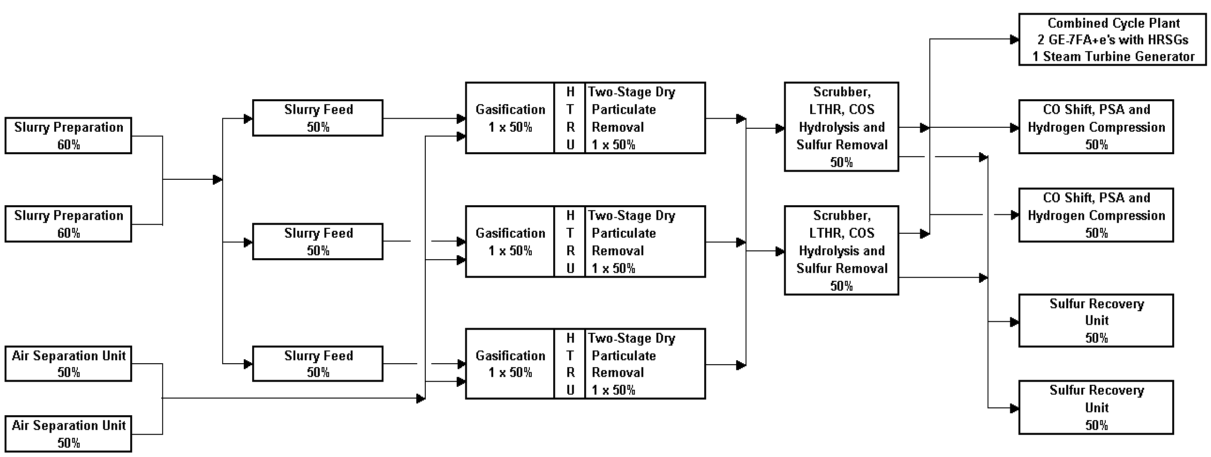


Notes: Capacity percentages are based on total plant capacity.

Figure IV.2

Subtask 1.3 Next Plant - Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

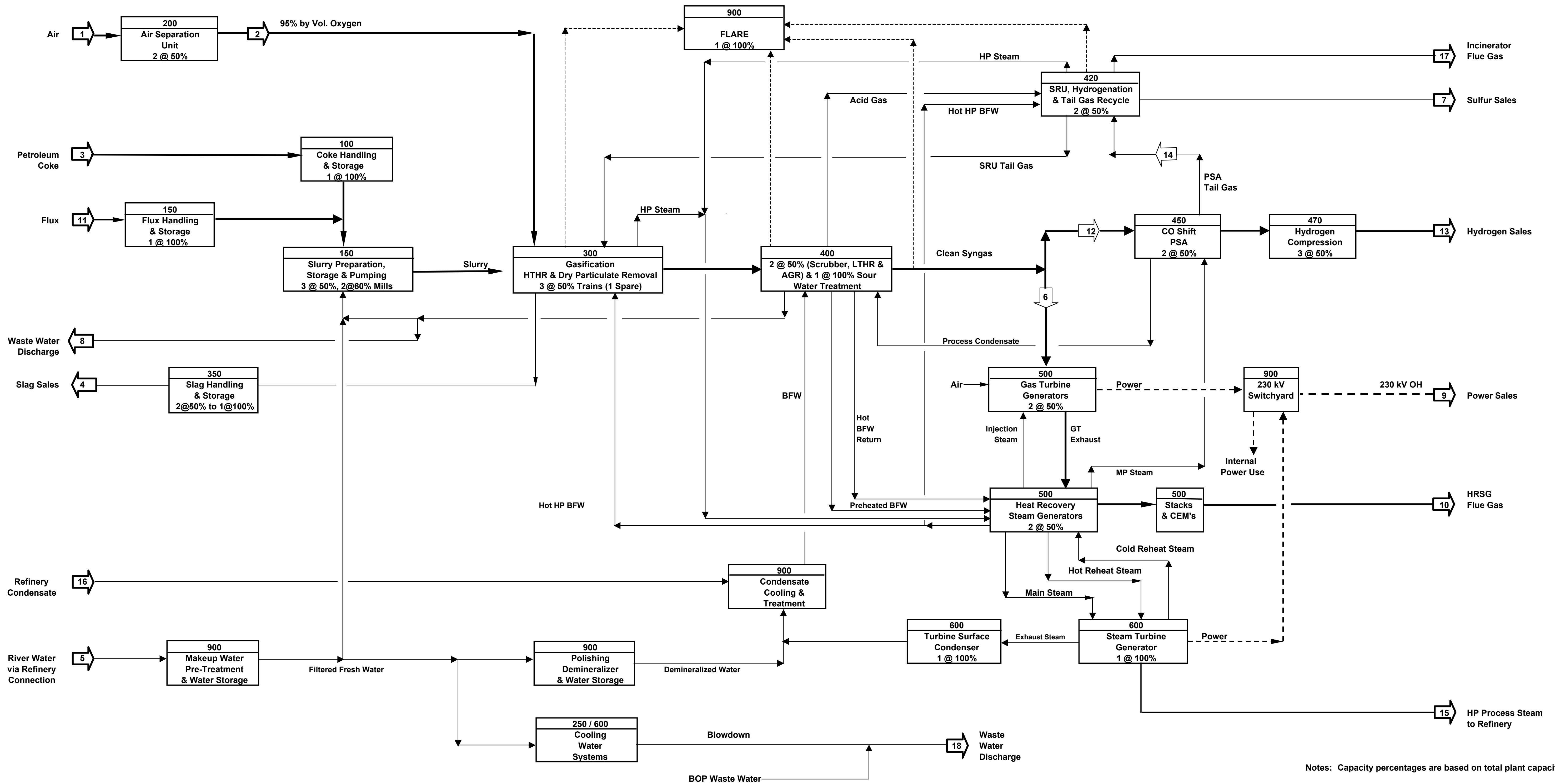


Notes: Capacity percentages are based on total plant capacity.

Figure IV.3

Block Flow Diagram of the Next Optimized

Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coke	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	Flux	Syngas	Hydrogen	Tail Gas	HP Steam	Condensate	Flue Gas	Water			
Flow	25,961	5,954	5,417	195.1	2,611,500	1,016,830	373.4	49,177	474,000	7,966,800	110.6	363,028	80	93.4	980,000	686,000	658,750	504,000			
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Tons/Day	Lb/Hr	MMSCFD	MMSCFD	Lb/Hr	Lb/Hr	Lb/Hr	Lb/Hr			
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	NA	350	1,000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	Ambient	180	70	530	332	80	NA	253	NA	530	120	113	750	190	500	71			
HHV Btu/lb	NA	NA	14,848	NA	NA	3,725	NA	NA	NA	NA	NA	3,725	NA	753	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	14,548	NA	NA	3,533	NA	NA	NA	NA	NA	3,533	NA	659	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,703	NA	NA	3,788	NA	NA	NA	NA	NA	1,352	1,083	281	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	6,567	NA	NA	3,592	NA	NA	NA	NA	NA	1,282	917	246	NA	NA	NA	NA			
Notes	Dry Basis	5,615 O2	Dry Basis	15%Wtr.	5,223 GPM	To GT	Sales	98 GPM	230 kV			For H2	Sales	373 MLb/hr	Sales	Return		1,008 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure IV.3

Subtask 1.3

NEXT OPTIMIZED PETROLEUM COKE IGCC

COPRODUCTION PLANT

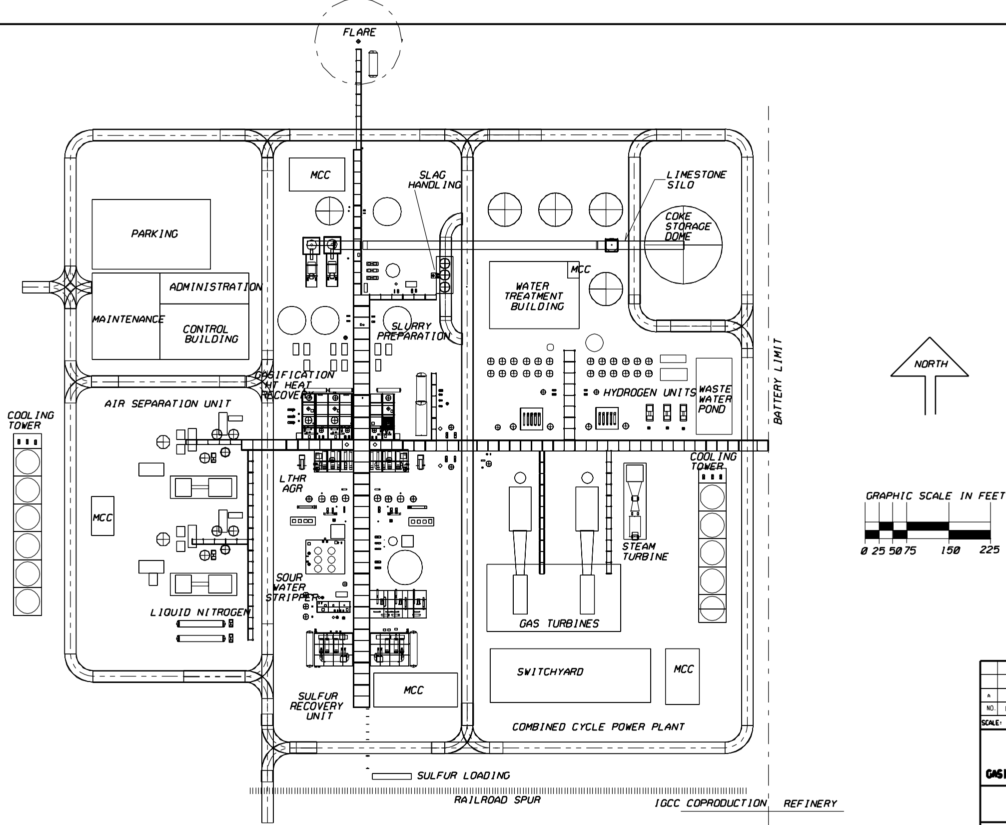
BLOCK FLOW DIAGRAM

File: Fig IV.3 1.3NP BFD R1.xls February 21, 2002

Figure IV.4

Site Plan of the Next Optimized

Petroleum Coke IGCC Coproduction Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A							

SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

PET-COKE COPRODUCTION PLANT
SUBTASK 1.3 NEXT PLANT

SITE PLAN

JOB NO: 24355-104 DRAWING NO: SK - 00118 REV. A

Figure IV.5

Artist's Conception of the Next Optimized

Petroleum Coke IGCC Coproduction Plant

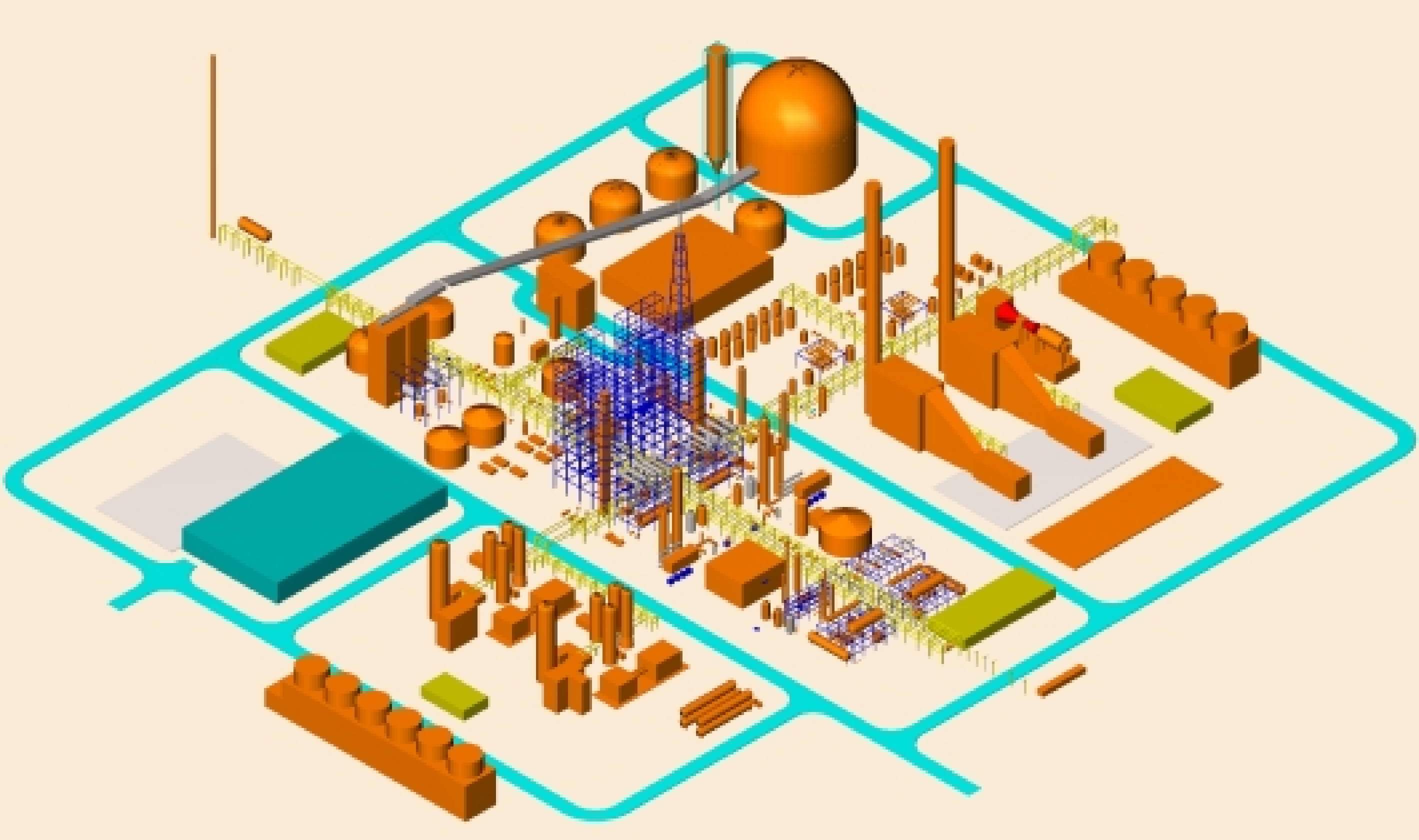
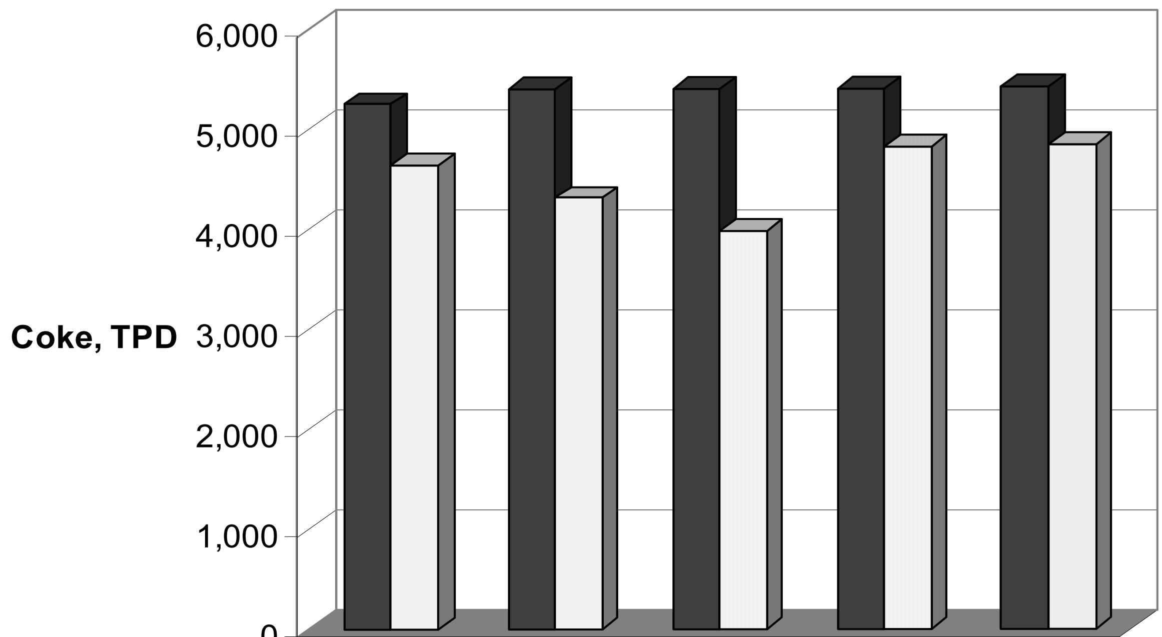


Figure IV.6

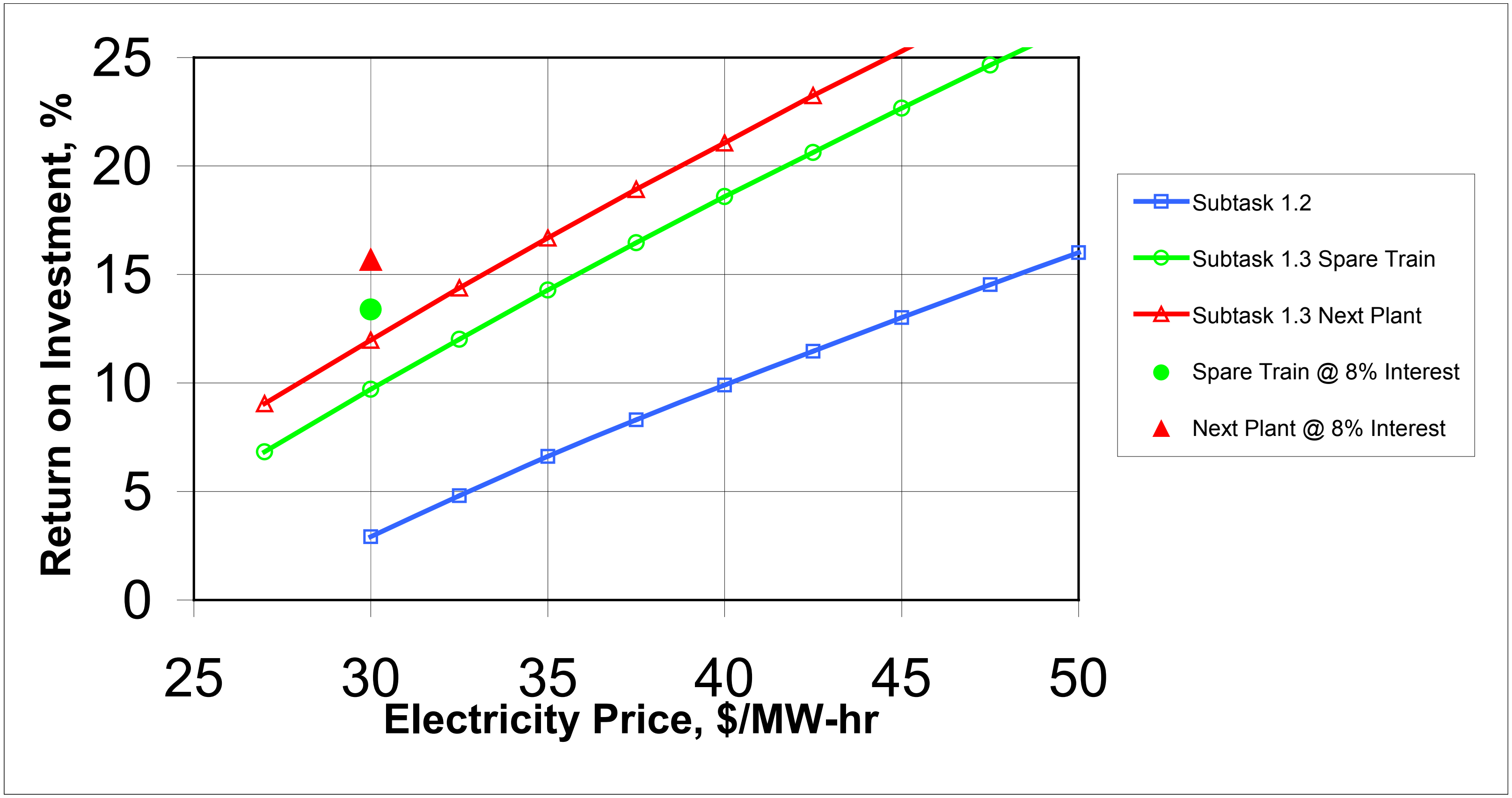
Design and Daily Average Coke Consumptions



	Subtask 1.2	1.3 Base Case	1.3 Min Cost	1.3 Spare Train	1.3 Next Plant
Design	5,249	5,399	5,399	5,399	5,417
Average	4,635	4,310	3,973	4,814	4,842

Figure IV.7

Effect of Power Selling Price on the Return on Investment



Chapter V

Coal Cases

This study investigated five coal-fueled IGCC plants to compare the relative performance, merits, and costs of the optimized coal IGCC cases on a common basis as measured by net present value (NPV), return on investment (ROI), and the cost of electricity. The five plants discussed in this chapter are:

1. The Subtask 1.1 Wabash River Greenfield Plant,
2. The future Subtask 1.4 Optimized Coal to Power IGCC Plant,
3. The Subtask 1.5A Coal Fueled IGCC Power Plant,
4. The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant,
5. The Subtask 1.7 Coal to Hydrogen Plant

The first three of the above plants are single-train coal fueled IGCC power plants. The Subtask 1.6 1,000 MW plant essentially is a four-train power plant. The Subtask 1.7 is a coal fueled gasification plant in which hydrogen is the principal product. In addition, Subtask 1.5 includes the design of the Subtask 1.5B coke fueled single-train IGCC power plant for comparison with the Subtask 1.5A coal fueled plant.

These cases were considered because they are the likely coal-fueled IGCC plant configurations that may be the first generation of clean-power-from-coal plants. The results of these case studies will allow future coal-fueled power plant owners to investigate various gasification plant options and also to identify future R&D needs which will further reduce the cost of electricity.

The following discussion of the above cases provides sufficient information to also allow assessment of the proposed designs compared to other IGCC and technology options.

V.1 The Subtask 1.1 Wabash River Greenfield Plant

The Subtask 1.1 Wabash River Greenfield Plant replicates the as-built Wabash River facility that was developed during the Wabash River Repowering Project and as was subsequently modified on a greenfield site. The primary objective for developing this plant design was to develop an accurate and documented cost basis starting from the actual Wabash River costs to use for the subsequent plant designs. In developing this case, new equipment was incorporated to replace the 1953 Westinghouse steam turbine, coal handling equipment, condensed and circulating water systems, and offsites. First-off-a-kind and project specific construction costs, such as site specific costs, were excluded.

The Subtask 1.1 Wabash River Greenfield Plant processes 2,259 TPD of dry Illinois No. 6 Coal to make 269.3 MW of export power, 57 TPD of sulfur, and 356 TPD of slag. The General Electric 7FA gas turbine produces 192 MW of power, and the newer, more efficient steam turbine generates 118 MW. The plant consumes 40.7 MW of power internally leaving 269.3 MW available for export. The plant has a heat rate of 8,912 Btu (HHV)/kW-hr, or a 38.3% thermal efficiency. Appendix A contains a detailed description of the Subtask 1.1 Wabash River Greenfield Plant.

Table V.1 summarizes the design and daily average feed, product and emissions rates for the Subtask 1.1 greenfield plant. The plant as configured at the start of this study would cost about 452.6 MM$ (mid-year 2000 basis) including all revisions and modifications that were made to the repowering project to improve performance.

Using the previously described economic parameters, the plant requires a 67.5 $/MW-hr current power selling price to produce a 12% return on investment without natural gas backup. When this study was started, the Wabash River facility was not configured to use backup natural gas to fire the gas turbine when syngas was unavailable. Therefore, that option was not considered for this case. In actuality, the plant was modified to use backup natural gas during the summer of 2001.

V.2 The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant

The Nominal 1,000 MW Coal IGCC Power Plant is an optimized design for a current base-loaded coal power plant located at a Mid-West site. This is a four gasification train plant with each gasification train containing a single gasifier vessel. The power block contains four General Electric 7FA+e combustion turbines (210 MW each) and two steam turbines (232.6 MW each). The gasification area is based on the Subtask 1.3 Next Plant design and uses Global Energy's current E-GAS™ gasifier with an advanced dry system for removing particulates from the syngas. This system consists of a cyclone, which removes over 90% of the particulates, followed by a dry filter system.

Not all sections of the plant contain four trains. Wherever possible, the number of trains was reduced to two or three to take advantage of the economies of scale. There are two slurry preparation areas, three air separation units, two wet scrubbers, two low temperature heat recovery areas, two COS hydrolysis reactors, two sulfur removal areas, and two sulfur recovery plants. The EPC cost of the plant is 1,231 MM$ (mid-2000) or 1,066 $/kW. On a $/kW basis, the Subtask 1.6 plant costs 36% less than the Subtask 1.1 plant. This is below the predicted cost for the advanced single-train Subtask 1.4 plant which will be described later. Appendix G provides a detailed description of the Subtask 1.6 plant

Table V.1 compares the performance and cost of this plant with that of the Subtask 1.1 Wabash River Greenfield Plant. The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant consumes 9,266 TPD of dry Illinois No. 6 coal and produces 1154.6 MW of export power, 237 TPD of sulfur and 1,423 TPD of slag. The plant has a heat rate of 8,526 Btu (HHV)/kW-hr, or a 40.0% thermal efficiency (HHV), which is almost 2% better than the Wabash River Greenfield Plant.

Figure V.1 is a block flow diagram of the Subtask 1.6 Optimized 1,000 MW Coal IGCC Power Plant. It also shows the major stream flow rates. Figure V.2 is a site plan for the plant, and Figure V.3 is an artists' conception of the facility. Although the plant produces over four times the amount of export power, the process section of the plant occupies only about three times the plot area of the Wabash River Greenfield Plant. The compression of the plant into a smaller plot area while still maintaining accessibility during construction and for maintenance resulted in significant cost savings because less interconnecting piping and site work are required.

Based on the financial parameters discussed previously, the Subtask 1.6 plant requires a current power selling price for a 12% after tax ROI of 44.4 $/MW-hr without natural gas backup, and 40.2 \$/MW-hr with natural gas backup. Under today's conditions of low inflation, if an 8% loan interest rate with the same 3% upfront financing fee can be obtained, the required power selling price drops to 37.8 \$/MW-hr with backup natural gas.

Because the availability analysis for the Subtask 1.6 plant showed that all four gasification trains would be operating simultaneously for only about 36% of the time, an alternate Subtask 1.6 design case was considered in which each gasification train was enlarged to 33.3% of the total plant capacity. This redesign increased the time when sufficient syngas would be available to fire all four gas turbines to 42% with only a moderate increase in the plant cost of about 43 MM\$. As a result, the required power selling price for a 12% ROI dropped to 40 \$/MW-hr without natural gas backup and to 38.9 \$/MW-hr with natural gas backup.

With an 8% loan rate, the required power selling prices drop even lower. For the case without backup natural gas, the required power selling price for a 12% ROI drops to 37.2 \$/MW-hr and to 36.4 \$/MW-hr with backup natural gas. At these power prices, this coal-fired 1,000 MW IGCC power plant can be competitive with new natural gas combined cycle power plants using 3.2 to 4.0 \$/MMBtu (HHV) natural gas.

V.3 The Subtask 1.4 and 1.5A Single-Train IGCC Power Plants

V.3.1 The Subtask 1.5A Coal IGCC Power Plant

The Subtask 1.5 coal and coke fueled single-train IGCC power plants were based on the previously described original Subtask 1.3 design. These plants incorporate a gasification area that was developed as a result of the Value Improving Practices and optimization efforts that were part of Subtask 1.3. Particulates are removed from the syngas by a cyclone followed by a wet scrubber. Both Subtask 1.5 plants use the newer, larger, and more efficient General Electric 7FA+e combustion turbine (210 MW capacity) rather than the older 7FA model (192 MW capacity) used at the Wabash River facility. With increased steam dilution, the 7FA+e turbines have significantly reduced NOx emissions. The Subtask 1.5 coal and coke single-train IGCC power plants are described in detail in Appendix F.

Both the Subtask 1.5 coal and coke plants are very similar in design and contain basically the same equipment as shown in Appendix F. The major differences between the two plants were enumerated in Section IV.2 of the previous chapter. Table V.2 contains a concise summary of the performance of these plants.

The Subtask 1.5A coal fueled power plant consumes 2,335 TPD of dry Illinois No. 6 coal and produces 284.5 MW of export power, 60 TPD of sulfur and 364 TPD of slag. The plant has a heat rate of 8,717 Btu (HHV)/kW-hr, or a 39.1% thermal efficiency (HHV). The plant cost 375 MM\$ (mid-year 2000) or 1,318 \$/kW of export power.

The Subtask 1.5B coke fueled power plant consumes 1,977 TPD of dry delayed petroleum coke and 71 TPD of flux. It produces 291.3 MW of export power, 136 TPD of sulfur and 71 TPD of slag. The plant has a heat rate of 8,397 Btu (HHV)/kW-hr, or a 40.6% thermal efficiency (HHV). The plant cost 367 MM\$ (mid-year 2000) or 1,262 \$/kW of export power. It is more efficient and costs slightly less than the corresponding coal plant primarily because it does not have to process as much ash (mineral matter) which leaves the system as slag, and it does not have makeup water treatment facilities since it gets its makeup water from the refinery.

Both of the Subtask 1.5 plants cost over 75 MM$ less that the Subtask 1.1 Wabash River Greenfield Plant and produce more export power showing the effect of the improvements that have been made as a result of this study and the larger and more efficient combustion turbine. On a $/kW basis, the Subtask 1.5A coal IGCC plant costs over 22% less than the Subtask 1.1 plant.

The required power selling price for a 12% ROI for the Subtask 1.5A coal fueled plant is 53.9 $/MW-hr without natural gas backup and 48.8 $/MW-hr with natural gas backup. These are 20 and 22% reductions in the required power price compared to the Subtask 1.1 plant.

The required power selling prices for a 12% ROI for the Subtask 1.5A petroleum coke fueled plant are even lower; 43.9 $/MW-hr without natural gas backup and 40.6 $/MW-hr with natural gas backup. These prices are lower primarily because the petroleum coke has an effective cost of 0 $/ton compared to the 22 $/ton cost of the dry coal.

V.3.2 The Subtask 1.4 Future Optimized IGCC Power Plant

The future Subtask 1.4 Optimized Coal to Power IGCC Plant is a future plant design that is based upon an advanced “G/H-class” combustion turbine that is expected to be commercially available at the end of the decade. The design for this plant was developed starting from the optimized Subtask 1.3 petroleum coke plants. During the VIP exercise some ideas were generated that were specifically for coal and some that were specifically for coke. Those ideas that were specifically for coal were included in the Subtask 1.4 design. In addition, some other ideas that still need some further development also were included because they are expected to be proven by the time the plant will be designed. Quantification of the effect of these VIP improvements for this case compared to a base case (as is done in Table III.3) is difficult because of the differences in plant size and gas turbine technology. Because these are single train plants, availability improvements have a smaller contribution, and the larger plant size will have a greater effect because of the economies of scale.

This is an integrated plant that uses an advanced, higher-pressure gasifier. The gasification area also contains some advances that still need further development and testing such as the use of a “hot” cyclone upstream of the high temperature heat recovery system for particulate removal (rather than downstream as in the Subtask 1.3 and 1.6 plants) and slurry feed vaporization (SFV). With SFV, all the coal slurry is injected solely into the second stage of the gasifier where the hot syngas leaving the first stage evaporates the slurry water. Dried particulates and unreacted coal are collected by the cyclones and recycled back to the first stage of the gasifier.

The Subtask 1.4 Optimized Coal to Power IGCC Plant consumes 3,007 TPD of dry Illinois No. 6 coal and produces 416.5 MW of export power, 76.7 TPD of sulfur and 462 TPD of slag. The plant has a heat rate of 7,671 Btu (HHV)/kW-hr, or a 44.5% thermal efficiency (HHV). This is over a 6% increase in thermal efficiency compared to the Subtask 1.1 Wabash River Greenfield Plant. The plant cost is 464.6 MM$ (mid-year 2000) or 1,115 $/kW of export power. On $/kW basis, the Subtask 1.4 plant costs one-third less than the Subtask 1.1 plant.

The required power selling price for a 12% ROI for the Subtask 1.4 Optimized Coal to Power IGCC Plant is 42.8 $/MW-hr without natural gas backup and 39.8 $/MW-hr with natural gas backup at a 10% loan interest rate. These are 36% and 41% reductions in the required power cost compared to the Subtask 1.1 plant, respectively. With an 8% loan interest rate, the required power selling price for a 12% return on investment drops to 39.9 $/kW-hr without backup natural gas and to 37.3 $/kW-hr with backup natural gas.

This plant is not economic compared to the 2005 advanced natural gas combined cycle plant, which has required power selling prices of 36.3 and 35.4 $/Mw-hr with $3.00 $/MMBtu HHV gas with 10 and 8% loan interest rates, respectively. However, the difference between the two technologies is closing. As further improvements are made and/or natural gas prices increase, the cost differences will continue to shrink.

Since the Subtask 1.4 design was finalized, two additional improvements were developed; namely improved designs for the syngas cooler heat exchanger and the sour water stripper. The improved sour water stripper design uses more corrosion resistant (and expensive) metallurgy that allows the build up of chlorides to higher levels in the wash water. This significantly reduces the size of the stripper and associated equipment as well as reducing the amount of steam consumed. The next result of these two enhancements is an 8.4 MW increase in the net power output and a 0.9 MM$ increase in the plant cost or 1,096 $/kW of export power. The thermal efficiency increases to 45.4%. This reduces the required power selling prices for a 12% ROI by about 0.7 to 0.8 $/MW-hr or about 2%.

The next generation of gasifiers will include the best features of the preceding coke and coal gasifiers (such as full slurry quench) leading to lower electricity costs and higher efficiencies. In addition, other design enhancements have been identified but have not yet been quantified. Combined, they should allow the next generation IGCC plant to approach a 50% thermal efficiency and a capital cost of 1,000 $/kW-hr. Therefore, these IGCC plants should be competitive with other coal technologies, both today and in the future.

Cost projections based on past demonstration projects have been fairly high (Subtask 1.1 is 1,681 $/kW for 269 MW). The EIA reference case estimate is 1,306 $/kW including contingency or 1,220 $/kW excluding contingency for a 428 MW IGCC plant.[1] This study estimates that through the VIP and optimization procedures, the next generation of IGCC single-train plants could be 1,320 $/kW for a 285 MW plant, and a near future plant of 416 MW could be 1,120 $/kW (excluding contingency, risk and fees). A next generation multi-train IGCC plant could be about 1,070 $/kW (excluding contingency, risk and fees) with a future multi-train plant being less than 1,000 $/kW. In comparison EIA cost projections for a 400 MW pulverized coal (PC) units are 1,092 $/kW including contingency or 1,021 $/kW excluding contingency.[1] Therefore, based on this study, it appears that the DOE projected costs for coal fueled IGCC plants may be conservative. Additional research will further reduce IGCC plant costs and increase their efficiency. Compared to conventional pulverized coal units, IGCC plants have an efficiency advantage (40 to 45% thermal efficiency vs. 35 to 37%), which will become more important as fuel costs increase. Furthermore, IGCC units have superior environmental performance.

[1] Energy Information Administration, Assumptions to the Annual Energy Outlook 2001, www.eia.doe.gov/oiaf/aeo/assumption/, pages 69 and 78, December 2000.

Table 13 on page 75 of the EIA *Annual Energy Outlook 2001* estimates the cost of producing electricity from an advanced pulverized coal plant of conventional design with a 36.9% thermal efficiency at 43.2 $/MW-hr.[2] About 72% of this cost is attributable to the capital cost of the plant, 18% to the fuel cost, and 10% to the operating and maintenance costs. This clearly shows that the plant cost is the dominant factor, and must be decreased in order to significantly reduce the cost of electricity. Increasing the thermal efficiency to 40 to 45% will only reduce the electricity cost by 0.6 to 1.4 $/MW-hr, or about the same as a 1.5 to 4.3% decrease in the plant cost.

At present, IGCC plants are more expensive than pulverized coal plants, but their efficiency advantage is not sufficient to overcome the capital cost disadvantage. However, coke gasification appears to have better economics than either pulverized coal or coal IGCC plants because of the lower feedstock costs and slightly lower plant costs. Depending upon the specific project conditions, they may be competitive with coal plants. Further IGCC plant cost reductions are required for coal IGCC plants to be less costly than conventional coal power plants.

Although the reduction in the cost of electricity from increased efficiency is dominated by the capital cost, there are environmental advantages which have not been quantified. Increased efficiency means less coal is burned, and less CO_2 is produced per MW of power generated. Furthermore, ICGG plants also produce less SOx and NOx. Quantification of the economic implications of the reduced IGCC plant emissions will depend upon project specific requirements and future environmental regulations.

Ultimately technology selection may well depend on project specific requirements. As more IGCC plants, either coal or coke, are built, capital and O&M costs should be reduced, giving IGCC a clear advantage, particularly as fuel prices increase. Now, and in the future, this report provides a starting point for evaluating the merits of IGCC plants.

V.3 The Subtask 1.7 Coal to Hydrogen Plant

The gasification block of the Subtask 1.7 Coal to Hydrogen Plant is based on the Subtask 1.3 Next Plant design, but the capacity was enlarged to process the same amount of Illinois No. 6 coal as the advanced Subtask 1.4 single train power plant. Figure V.4 is a block flow diagram of the Subtask 1.7 Coal to Hydrogen Plant that shows the major stream flows. From coal handling through the low temperature heat recovery area, the gasification block basically is the same as the Subtask 1.3 Next Plant except that it contains a spare gasifier vessel. A single air separation unit generates 99.5% pure oxygen for the gasifier rather than the 95.0% oxygen that is used for power production. Hydrogen sulfide is removed from the particulate-free syngas by scrubbing with Rectisol (rather than MDEA). The hydrogen sulfide-free syngas is divided between two parallel hydrogen production and purification trains. First the CO in the syngas goes to a “sweet” three-stage CO shift process. Carbon dioxide and unconverted CO are removed from the shifted syngas by a second scrubbing with Rectisol. Finally, the hydrogen is purified by two PSA (pressure swing adsorption) units with 90% recovery before being compressed to 1,000 psig for export. The two-step Rectisol treating is required to produce 99.0% pure hydrogen containing less than 10 ppmv of CO. The 99.0% pure hydrogen produced in Subtasks 1.2 and 1.3 cannot meet this 10 ppmv CO

[2] U. S. Department of Energy, Energy Information Administration, “Annual Energy Outlook 2001 with Projections to 2020,” December 2000, www.eia.doe.gov/oiaf/aeo.

specification because the PSA units alone will not remove the CO to this low level that is required for merchant hydrogen.

The remainder of the plant is single train. The PSA sweep gas goes to a steam boiler which generates high pressure superheated steam for the steam turbine. Medium pressure steam is extracted from the stream turbine for use in the CO shift reactors. The 70.6 MW of power produced by the steam turbine is insufficient to satisfy the electrical demand of the plant, and additional power has to be imported.

The use of Rectisol for CO_2 removal allows the recovery of a high purity CO_2 stream for use or sequestration. At the right location, the CO_2 could be compressed and used for enhanced oil recovery.

The Subtask 1.7 Coal to Hydrogen Plant is described in detail in Appendix H. It consumes 3,007 TPD of dry Illinois No. 6 coal and 18.4 MW of electric power to produce 142.1 MMscfd of 99.0% hydrogen, 76.4 TPD of sulfur, and 474.3 TPD of slag. Sulfur removal is 98.5%. The plant EPC cost is 529.8 MM$.

At the basic economic conditions described previously with 27.0 $/MW-hr power, the hydrogen must be sold for 2.79 $/Mscf to produce a 12% rate of return. This is not competitive with the assumed (current) price of hydrogen of 1.30 $/Mscf (about twice that of natural gas on a Btu basis). An 8% loan interest rate will lower the required hydrogen selling price by only 0.20 $/Mscf to 2.59 $/Mscf.

If the hydrogen purity specification can be relaxed to the same specification as used in Subtasks 1.2 and 1.3 by removing the 10 ppmv CO specification, then COS hydrolysis, a “sour” CO shift and MDEA scrubbing can be used for sulfur removal from the syngas. This change reduces the plant cost by about 58 MM$, and the plant now exports 39 MW of power. However, these changes only reduce the required hydrogen price for a 12% ROI to 2.60 $/Mscf with a 10% loan interest rate.

Based on these results, it appears that the most economic way to produce hydrogen from coal (with or without having a viable market for the byproduct CO_2) is to do it in a multi-train coproduction plant where power is the major product. In this manner, the incremental gasification area and OSBL costs are minimized. Furthermore, this would increase the availability of the hydrogen product since the syngas feed to the CO shift reactors could be obtained from one of two or more gasification trains. This coproduction scenario probably will be the best configuration for the Task 2 plants that will produce liquid petroleum products.

Table V.1

Design and Daily Average Feed and Product Rates for the Subtask 1.1and 1.6 Coal IGCC Power Plants

	Subtask 1.1 Wabash River Greenfield		Subtask 1.6 1,000 MW Coal IGCC Power Plant		
		Daily Average		Daily Average	
	Design	Without Backup Gas	Design	Without Backup Gas	With Backup Gas
Feeds					
Coal, TPD dry	2,259	1,705	9,266	7,018	7,018
Natural Gas, Mscfd	0	0	0	0	34,961
River Water, gpm	2,281	1,722	9,652	7,310	NC
Products					
Export Power, MW	269.3	203.2	1,154.6	874.5	1061.0
Sulfur, TPD	57	43	236.6	179.2	179.2
Slag, TPD	356	281	1,423	1,078	1,078
Performance					
Oxygen Consumption,					
TPD of 95% O_2	2,130	1,608	8,009	6,066	6,066
TPD O_2/TPD dry fuel	0.94	0.94	0.86	0.86	0.86
Water Discharge, gpm					
Process Water	120	91	59	45	45
Clear Water	643	485	1,618	1,225	NC
Total Discharge	763	576	1,677	1,270	NC
Heat Rate, Btu/kW (HHV)	8,912	8,912	8,526	8,526	8,245
Thermal Efficiency, %	38.3%	38.3%	40.0%	40.0%	41.4%
Emissions					
SO_2, lb/MW-hr	1.16	1.16	0.38	0.38	0.31
CO, lb/M-hr	0.21	0.21	0.04	0.04	NC
NOx, lb/MW-hr	0.60	0.60	0.24	0.24	NC
Sulfur Removal, %	96.8	96.8	98.9	98.9	98.9
Plant Area, acres	61		62		
EPC Cost, MM$[1]	452.6		1,231		
EPC Cost, $/kW	1,680		1,066		
Required Power Selling Price for a 12% ROI, $/MW-hr[2]		67.5		44.4	40.2

NA = Not Applicable NC = Not Calculated

NOTE:
1. The EPC costs are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants.
2. All power selling prices are on a current day basis. They increase at a rate of 1.7%/year.

Table V.2

Design and Daily Average Feed and Product Rates
for the Subtask 1.1, 1.4 and 1.5 Single-train Coal IGCC Power Plants

	Subtask 1.1 Wabash River Greenfield		Subtask 1.4 Optimized Coal to Power IGCC Plant			Subtask 1.5A Current Coal IGCC Power Plant			Subtask 1.5B Current Pet Coke IGCC Power Plant		
		Daily Average		Daily Average			Daily Average			Daily Average	
	Design	Without Backup Gas	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	With Backup Gas
Feeds											
Coal, TPD dry	2,259	1,705	3,007	2,400	2,400	2,335	1,826	1,826	NA	NA	NA
Petroleum Coke, TPD dry	NA	NA	NA	NA	NA	NA	NA	NA	1,977	1,546	1,546
Natural Gas, Mscfd	0	0	0	0	8,896	0	0	6,929	0	0	6,929
River Water, gpm	2,281	1,722	3,079	2,457	NC	2,836	2217	NC	2,525	1,975	NC
Flux, TPD	NA	NA	NA	NA	NA	NA	NA	NA	40	31	31
Products											
Export Power, MW	269.3	203.2	416.5	332.4	387.8	284.6	222.5	264.4	291.3	227.8	269.4
Sulfur, TPD	57	43	76.7	61.2	61.2	60	46.9	46.9	136	106.0	106.0
Slag, TPD	356	281	462	368.7	368.7	364	284.6	284.6	71	55.5	55.5
Performance											
Oxygen Consumption,											
TPD of 95% O_2	2,130	1,608	2,294	1,831	1,831	2,015	1,576	1,576	2,021	1,580	1,580
TPD O_2/TPD dry fuel	0.94	0.94	0.76	0.76	0.76	0.86	0.86	0.86	1.02	1.02	1.02
Water Discharge, gpm											
Process Water	120	91	0	0	0	72	56	56	665	520	520
Clear Water	643	485	703	561	NC	640	500	NC	597	467	NC
Total Discharge	763	576	703	561	NC	712	557	NC	1,262	987	NC
Heat Rate, Btu/kW (HHV)	8,912	8,912	7,671	7,671	6,656	8,717	8,717	8,429	8,397	8,397	8,172
Thermal Efficiency, %	38.3%	38.3%	44.5%	44.5%	51.3%	39.1%	39.1%	40.5%	40.6%	40.6%	41.8%
Emissions											
SO_2, lb/MW-hr	1.16	1.16	0.09	0.09	0.08	0.50	0.50	0.42	0.41	0.41	0.35
CO, lb/M-hr	0.21	0.21	0.11	0.11	NC	0.14	0.14	NC	0.14	0.14	NC
NOx, lb/MW-hr	0.60	0.60	0.30	0.30	NC	0.24	0.24	NC	0.24	0.24	NC
Sulfur Removal, %	96.8	96.8	99.7	99.7	99.7	98.5	98.5	98.5	99.4	99.4	99.4
Plant Area, acres	61		40			40			40		
EPC Cost, MM$[1]	452.6		464.6			375			367		
EPC Cost, $/kW	1,680		1,115			1,318			1,262		
Required Power Selling Price for a 12% ROI, $/MW-hr[2]		67.5		42.8	39.8		53.9	48.8		43.9	40.6

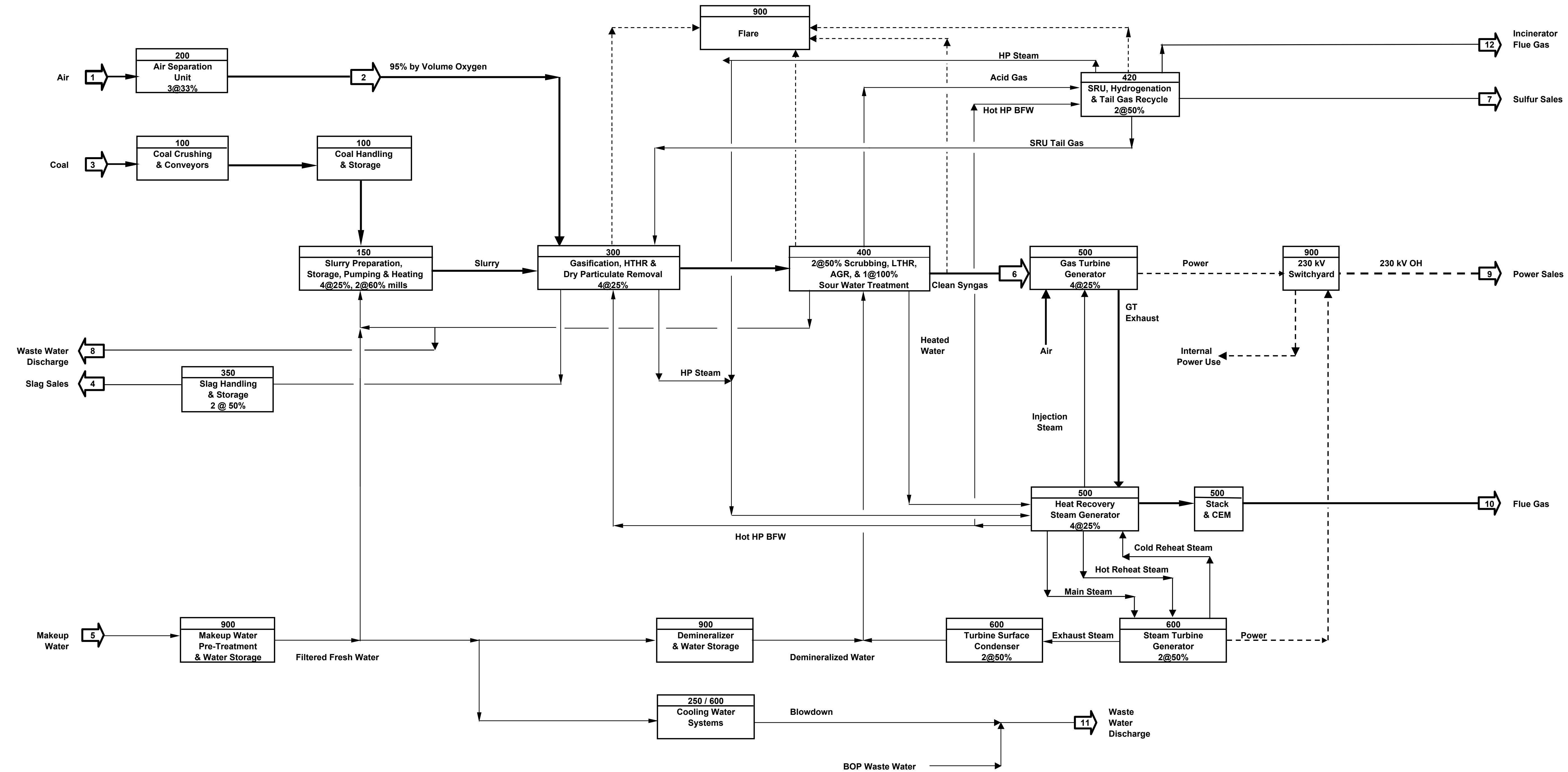
NA = Not Applicable   NC = Not Calculated

NOTE:
1. The EPC costs are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.
2. All power selling prices are on a current day basis. They increase at a rate of 1.7%/year.

Figure V.1

Block Flow Diagram of the Subtask 1.6

Optimized 1,000 MW Coal IGCC Power Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 34,922 Tons/Day	Oxygen 8,009 Tons/Day	Coal 9,266 Tons/Day	Slag 1,423 Tons/Day	Water 4,826,000 Lb/Hr	Syngas 1,741,575 Lb/Hr	Sulfur 236.6 Tons/Day	Water 29,443 Lb/Hr	Power 1,154,600 kWe	Flue Gas 15,934,000 Lb/Hr	Water 624,000 Lb/Hr	Flue Gas 21,359 Lb/Hr									
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	Atmos.	Atmos.									
Temperature - F	59	240	NA	NA	70	530	NA	80	NA	238	NA	500									
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,429	NA	NA	NA	NA	NA	NA									
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,125	NA	NA	NA	NA	NA	NA									
Energy - MM HHV/Hr	NA	NA	9,844	NA	NA	7,714	NA	NA	NA	NA	NA	NA									
Energy - MM LHV/Hr	NA	NA	9,478	NA	NA	7,184	NA	NA	NA	NA	NA	NA									
Notes	Dry Basis	7553 O2	Dry Basis	15%Wtr.	9,652 GPM	to GT	Sales	59 GPM	230 kV		1,248 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure V.1

Subtask 1.6

NOMINAL 1,000 MW COAL IGCC POWER PLANT

BLOCK FLOW DIAGRAM

File: Fig V.1 1.6 BFD R1.xls
February 20, 2002

Figure V.2

Site Plan of the Subtask 1.6

Optimized 1,000 MW Coal IGCC Power Plant

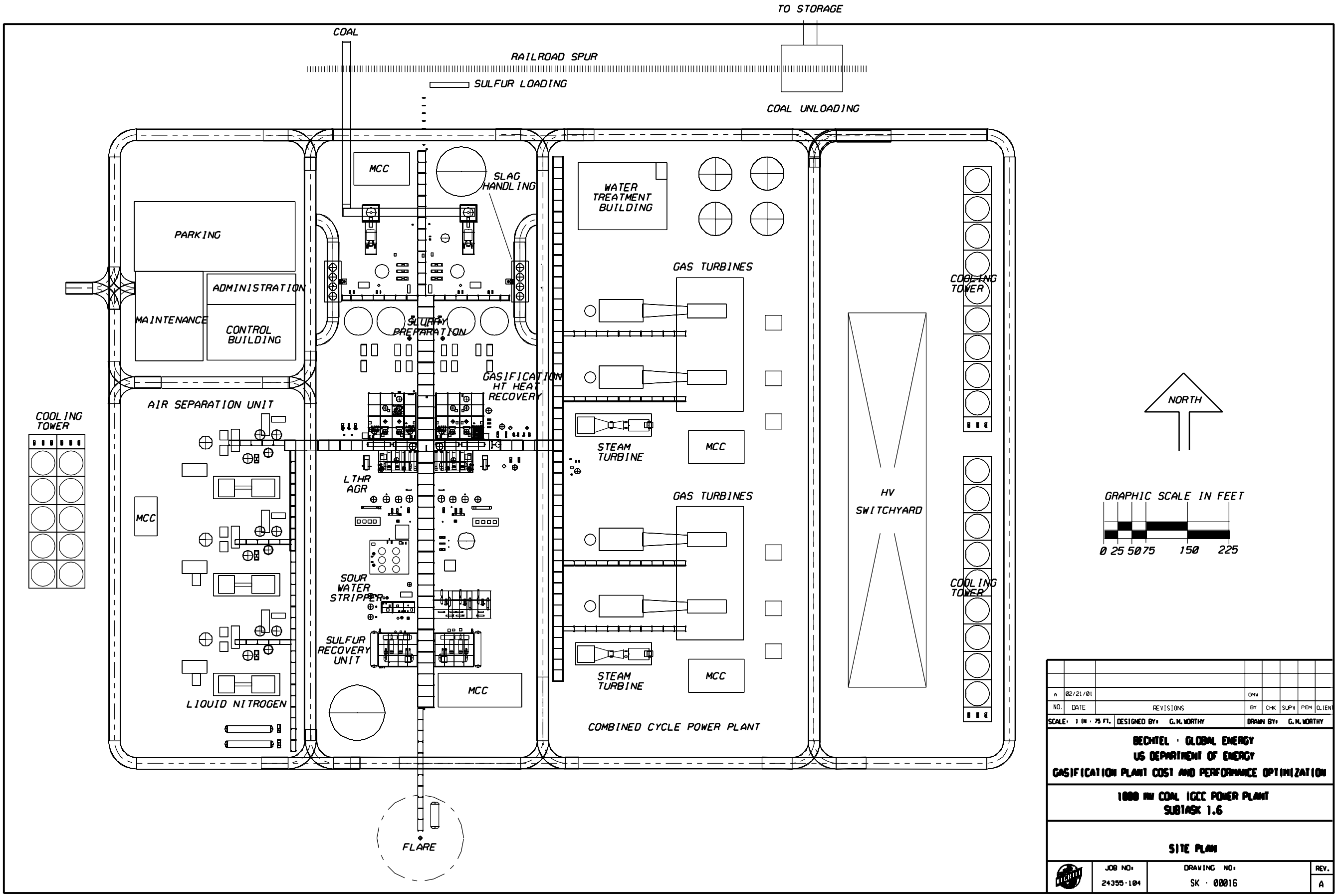

TO STORAGE
COAL
RAILROAD SPUR
SULFUR LOADING
COAL UNLOADING
MCC
SLAG HANDLING
WATER TREATMENT BUILDING
PARKING
ADMINISTRATION
MAINTENANCE
CONTROL BUILDING
SLURRY PREPARATION
GAS TURBINES
COOLING TOWER
GASIFICATION HT HEAT RECOVERY
AIR SEPARATION UNIT
COOLING TOWER
STEAM TURBINE
MCC
NORTH
LTHR AGR
MCC
HV SWITCHYARD
GAS TURBINES
GRAPHIC SCALE IN FEET
0 25 50 75 150 225
SOUR WATER STRIPPER
COOLING TOWER
SULFUR RECOVERY UNIT
STEAM TURBINE
MCC
MCC
LIQUID NITROGEN
COMBINED CYCLE POWER PLANT
FLARE
A 02/21/01 GMW
NO. DATE REVISIONS BY CHK SUPV PEM CLIENT
SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY
BECHTEL · GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION
1000 MW COAL IGCC POWER PLANT
SUBTASK 1.6
SITE PLAN
JOB NO: 24355-104
DRAWING NO: SK - 00016
REV. A

Figure V.3

Artist's Conception of the Subtask 1.6

Optimized 1,000 MW Coal IGCC Power Plant

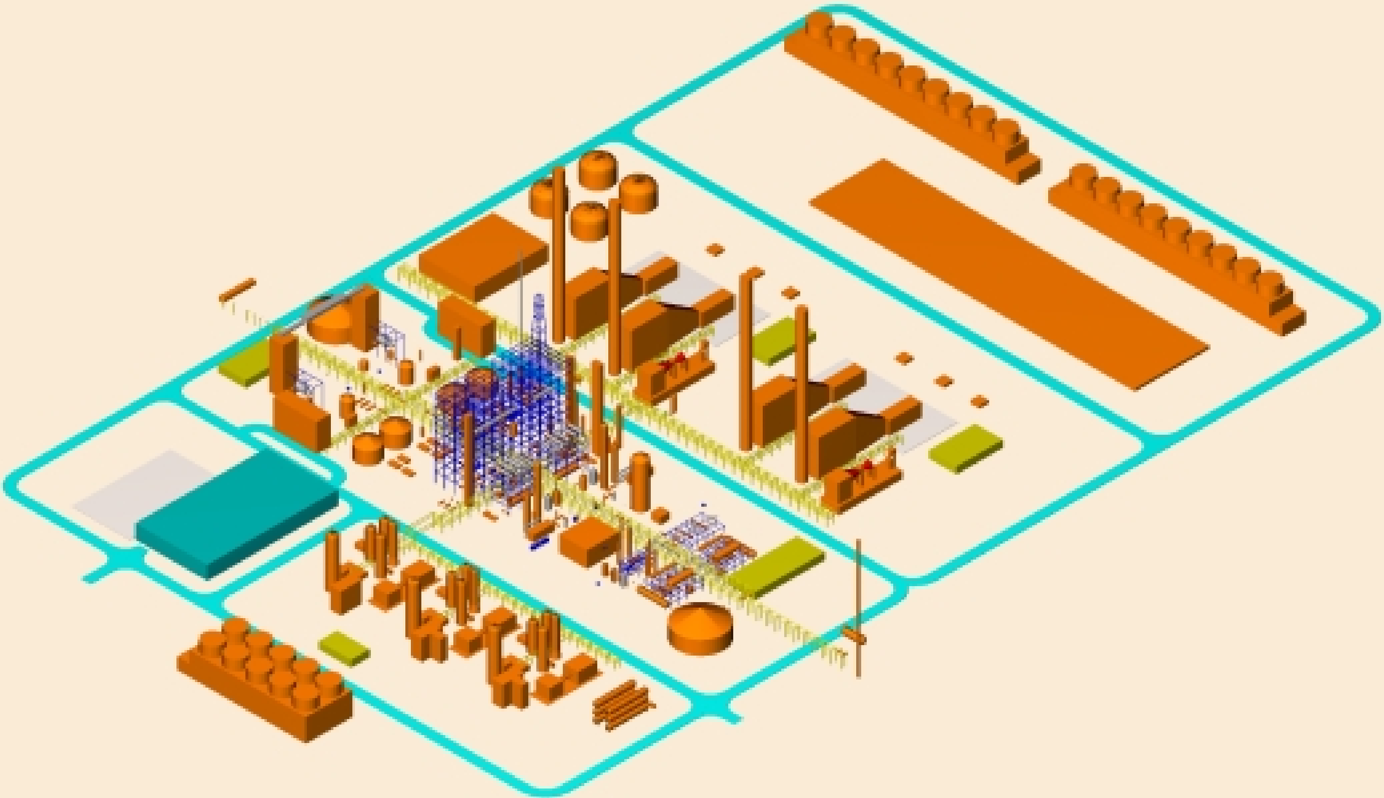
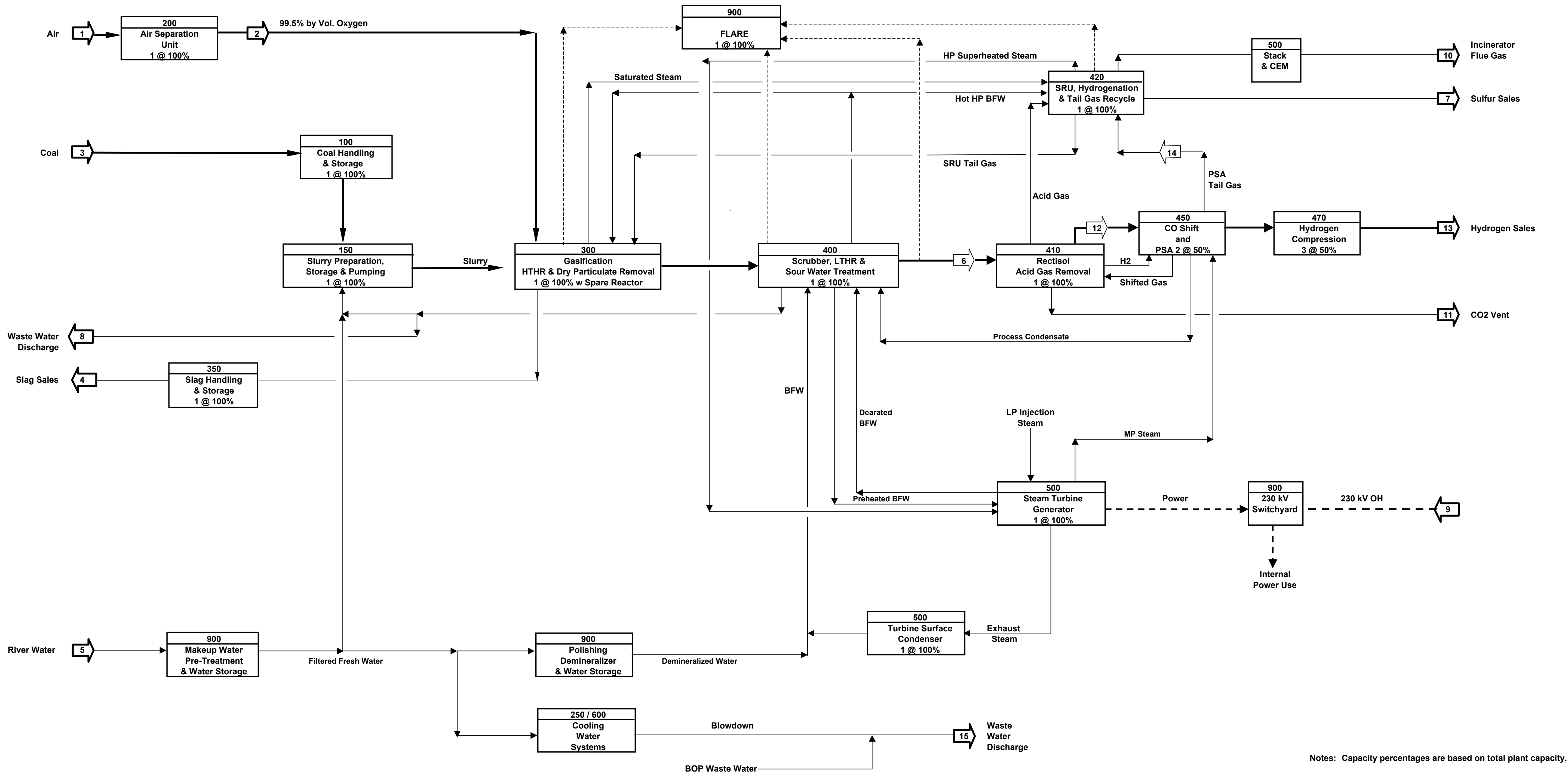


Figure V.4

Block Flow Diagram of the

Subtask 1.7Coal to Hydrogen Plant



Notes: Capacity percentages are based on total plant capacity.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coal	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	CO2	Syngas	Hydrogen	Tail Gas	Water						
Flow	11,590	2,522	3,007	474.3	1,229,000	548,767	76.4	31,215	18,400	986,470	593,752	807,875	142	22,981	307,000						
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Lb/Hr	Lb/Hr	MMSCFD	Lb/Hr	Lb/Hr						
Nominal Pressure - psig	Atmos.	649	NA	NA	50	400	NA	62	NA	Atmos.	Atmos.	375	1,000	5	Atmos.						
Temperature - F	70	240	Ambient	193	70	81	333	80	NA	500	50	509	120	53	71						
HHV Btu/lb	NA	NA	12,749	NA	NA	4,999	NA	NA	NA	NA	0	3,026	57,832	23,151	NA						
LHV Btu/lb	NA	NA	12,275	NA	NA	4,653	NA	NA	NA	NA	0	2,817	48,893	21,724	NA						
Energy - MM HHV/hr	NA	NA	3,195	NA	NA	2,743	NA	NA	NA	NA	0	2,445	1,909	532	NA						
Energy - MM LHV/hr	NA	NA	3,076	NA	NA	2,553	NA	NA	NA	NA	0	2,276	1,614	499	NA						
Notes	Dry Basis	2,507 O2	Dry Basis	15%Wtr.	2,458 GPM		Sales	62 GPM	230 kV			For H2	99.6% H2		614 GPM						

DOE Gasification Plant Cost and Performance Optimization

Figure V.4

Subtask 1.7

COAL TO HYDROGEN PLANT

BLOCK FLOW DIAGRAM

File: Fig V.4 1.7 BFD R1.xls February 21, 2002

Environmental Impacts

Gasification is viewed as the environmentally superior process for power generation from coal or petroleum coke. The Wabash River Repowering Project demonstrated the superior environmental performance of gasification in terms of SOx, NOx, and particulate emissions. The optimized systems developed in this study have sulfur removal rates that are 98.5% or greater, and generally are better than 99%. Gas turbine NOx emissions are less than 10 ppmv dry.

The following mini-table compares typical emissions from a pulverized coal combustion plant and a petroleum coke CFB plant with those from the Subtask 1.5B and 1.6 IGCC plants on a per unit of energy input basis.

Typical Emissions in lb/MMBtu per unit of Energy Input[1]

	Coal-Fueled		Petroleum Coke-Fueled	
	Pulverized Coal Combustion Plant	Subtask 1.6 IGCC Plant	CFB Boiler	Subtask 1.5B IGCC Plant
SOx	0.2	0.044	0.37	0.047
NOx*	0.15	0.028	0.15	0.028
Particulates	0.01	NIL	0.02	NIL

* Without SCR

Generally the emissions for the gasification plants are almost an order of magnitude better. With a selective catalytic reduction (SCR) system, the NOx levels can be further reduced for both plants.

In an IGCC plant, there are two sources of emissions, the combustion turbine/HRSG stack and the incinerator stack. Appendices A though H each contain a table showing the SOx, NOx and CO emissions from each stack and the total plant emissions for each case. For the optimized cases, the NOx emissions from the combustion turbine/HRSG stack are lower than the non-optimized cases because of the increased amount of steam diluent being used.

In the Subtask 1.2 and 1.3 coproduction plants, the incinerator consumes the tank vent and purge gases. In the Subtask 1.2 case, the PSA sweep gas is consumed in the adjacent refinery, and its associated emissions are attributed to the refinery. In the Subtask 1.3 cases, the PSA sweep gas is burned in the incinerator to make steam, which is used to increase the power production, and accounts for the higher emissions.

No solid adsorbents are used for syngas cleanup in any of these gasification plant cases other that the flux that is added with the petroleum coke. Compared to a petroleum coke combustion plant, the IGCC coproduction plant generates an order of magnitude less solid waste. The solid waste generated by a coal IGCC power plant also is less than that

[1] Pulverized coal combustion plant data are from Brun, K. and R. M. Jones, "Economic Viability and Outlook of IGCC form a Gas Turbine Manufacturer Perspective" (General Electric), 2001 Gasification Technologies Conference, San Francisco, CA, October 7-10, 2001. The SOx emissions were adjusted to the same coal sulfur level.

produced by a combustion plant with the relative amounts being dependent upon the mineral matter content in the coal.

In a gasification facility, heavy metals are very low because they are encapsulated in the slag. Other metals, such as mercury and selenium, are volatile and are detected in the syngas. Compared to a conventional combustion plant, metals removal should be easier because the cleanup can be done on the syngas at a higher pressure in a reducing environment rather than in the lower pressure, oxidizing environment of the effluent. Thus, the potential exists for effectively complete removal from the syngas by selective adsorbents, but additional research and development efforts are needed.

Ranked on a carbon content basis, coke has the highest carbon content followed by coal and natural gas. In a gasification system, essentially all of the carbon (approximately 99%) is converted to CO_2 and rejected in the gas turbine/HRSG vent and the incinerator vent. Therefore, without any CO2 mitigation, the CO_2 emissions essentially are related to the carbon content of the fuel.

In a carbon constrained environment, the CO_2 from gasification plants can easily be captured for sequestration or other uses. Even without CO_2 capture, CO_2 emissions are minimized because gasification plants are more efficient than coal combustion plants. The future Subtask 1.4 plant has a thermal efficiency of 44.5% (HHV) compared to the 35% to 37% thermal efficiencies of conventional coal power plants. Compared to a 36% efficient conventional combustion power plant, the Subtask 1.4 plant will generate 24% less CO_2 because it consumes 24% less coal. As gasification technology matures, further efficiency improvements are expected whereas little, if any, improvement appears likely in conventional pulverized coal combustion plants.

Another benefit of gasification technology is that it can be adapted to process wastes which otherwise would be disposed of in landfills. Besides producing merchant power or other products, gasification of these wastes reduces their volume, and the slag may be viable for other uses such as aggregate. Additional research and development efforts are needed to evaluate and promote waste gasification.

The review of potential warm gas cleanup systems contained in Appendix D showed that amine acid gas removal systems presently are the best for H_2S removal. However, the Selective Catalytic Oxidation of Hydrogen Sulfide (SCOHS), which is being developed by DOE/NETL, has the potential to be a simple cost effective method of H_2S removal that could achieve lower sulfur emissions. Also, several additional subsystems are required to make SCOHS an acceptable substitute for amine based sulfur removal systems. These sub-systems are: pre-cooling to 225°F, chloride removal, post reactor sulfur removal, trace element and ammonia removal, sour water stripping, syngas re-heating and moisturization, and catalyst regeneration tail gas cleanup. The report also discusses the research needs and impediments to commercialization such as: simultaneous COS hydrolysis or COS reaction to sulfur; operating at higher temperatures to avoid water or sulfur condensation; regeneration testing, and regeneration at lower temperatures (~650°F). The DOE/NETL research team believes these obstacles can be overcome with additional research and development efforts. If their testing and development efforts are successful, this system should be less costly than an amine based system and achieve lower sulfur emissions.

As natural gas and power prices increase and environmental constraints for coal fired generation tighten, coal IGCC will penetrate the power market. As more coal and coke

IGCC plants are built, further improvements can be expected which will lead to still cleaner and more environmentally friendly plants.

Chapter VII

Market Potential and Future Applications

VII.1 Market Potential

Integrated Gasification Combined Cycle (IGCC) and Coproduction (IGCP) plants are technically and economically ready for market expansion into a domestic power and energy market whose growth has been dominated by natural gas in recent years. As illustrated in the results of this study, gasification technologies have achieved economic parity with conventional coal fired plants in many power generation scenarios with less environmental impact. In refinery implementation scenarios, they provide a wide range of additional benefits including beneficial utilization of petroleum coke products and facilitating independence from the natural gas market.

There is a growing appreciation for the advantages of gasification in both the power and refinery industries as evidenced by a surge in market activity this year. Three new domestic gasification projects have been publicly announced, totaling over 2,000 MW of generation capacity. Global Energy received six formal solicitations for licensing gasification technology from other firms, was invited to speak at well over a dozen conferences and workshops, and has hosted two to five potential customer visits to the Wabash River facility each month from January to September. Inquiries for information on gasification technology and the results of this study have not been formally tracked, but typically two to three contacts a week are made.

VII.1.1 Coal

The domestic coal-to-power market is rebounding due to market and governmental concerns with natural gas price volatility, fuel diversity, and energy independence. Events in 2000 and 2001 have shown the fragile nature of the natural gas market, where regional supply restrictions led to incredible price swings and cascaded into power pricing surges and shortages. While this also spurred an increase in exploration and production of domestic natural gas resources, data suggests that the accessible reserves are becoming more costly to produce, and the long-term production potential has decreased. The environmental impacts of obtaining this production also are evoking greater debate at both the local and national levels.

Gasification is viewed as the environmentally superior process for power generation from coal. The superior environmental performance of the Wabash River facility, which was permitted in 1993 and demonstrated from 1995 to present, remains as the benchmark for the coal industry in terms of SOx, particulate emissions, and solid waste generation. Conventional combustion technology coal fired plants that have been announced in 2001 for Kentucky and Illinois are barely equivalent to the demonstrated performance of the Wabash River facility, even with state-of-the-art clean up systems on the flue gas exhaust. NOx emission performance of gasification is tied to the combustion turbine technology, which also has made great progress since the Wabash River installation. Continued advances in turbine technology will improve the penetration of gasification plants into ozone non-attainment areas.

Coal powered generation also is seen as a key to U.S. energy independence and reducing dependence on foreign energy sources. It is, as often mentioned in the literature, our most plentiful domestic energy resource with centuries of reserves in the ground. The distributed nature of the coal resources, rail and river transportation, and scattered locations of generation facilities also provides protection against potential terrorist attacks aimed at widespread disruption of the electrical generation systems in the U.S.

Both independent power producers and utilities are evaluating the gasification option for greenfield coal baseload power plants they seek to develop. In the last twelve months, 36 GW of coal fired power plants have been announced in the United States (see chart[1]). While the implementation of many of these planned plants has been affected by the current economic slowdown, it seems certain that their will be a new generation of coal fired power generation after nearly two decades of minimal activity, and that gasification will be a contender for a share of this new market expansion.

Further in the future, markets will develop for the repowering of aging, environmentally pressured coal fired plants and for the refueling of recent natural gas powered combined cycle plants.

VII.1.2 Petroleum Coke

Refineries in the United States also are being significantly impacted by the volatility of natural gas prices. In most refineries, the costs of their steam, hydrogen and power usage are tied to natural gas pricing. The refineries with cokers have the additional burden of having to sell or dispose of petroleum coke, the “bottom of the barrel” in the refining process. Much of this petroleum coke is sold for shipment overseas, but these markets are softening because of the additional refining and coking plants being brought onstream in the early part of this decade. World coker capacity is expected to grow from 6 million metric tons per year in 2000 to over 16 million metric tons per year by 2004 because of facilities in construction or final planning.[2] (These totals exclude China and the former Soviet Union). Much of this capacity is in the U.S. Gulf Coast, Mexico and South America, all of which will have the tendency to depress domestic prices. Delivered petroleum coke prices fluctuate, but generally they are minimal or negative at the refinery gates.

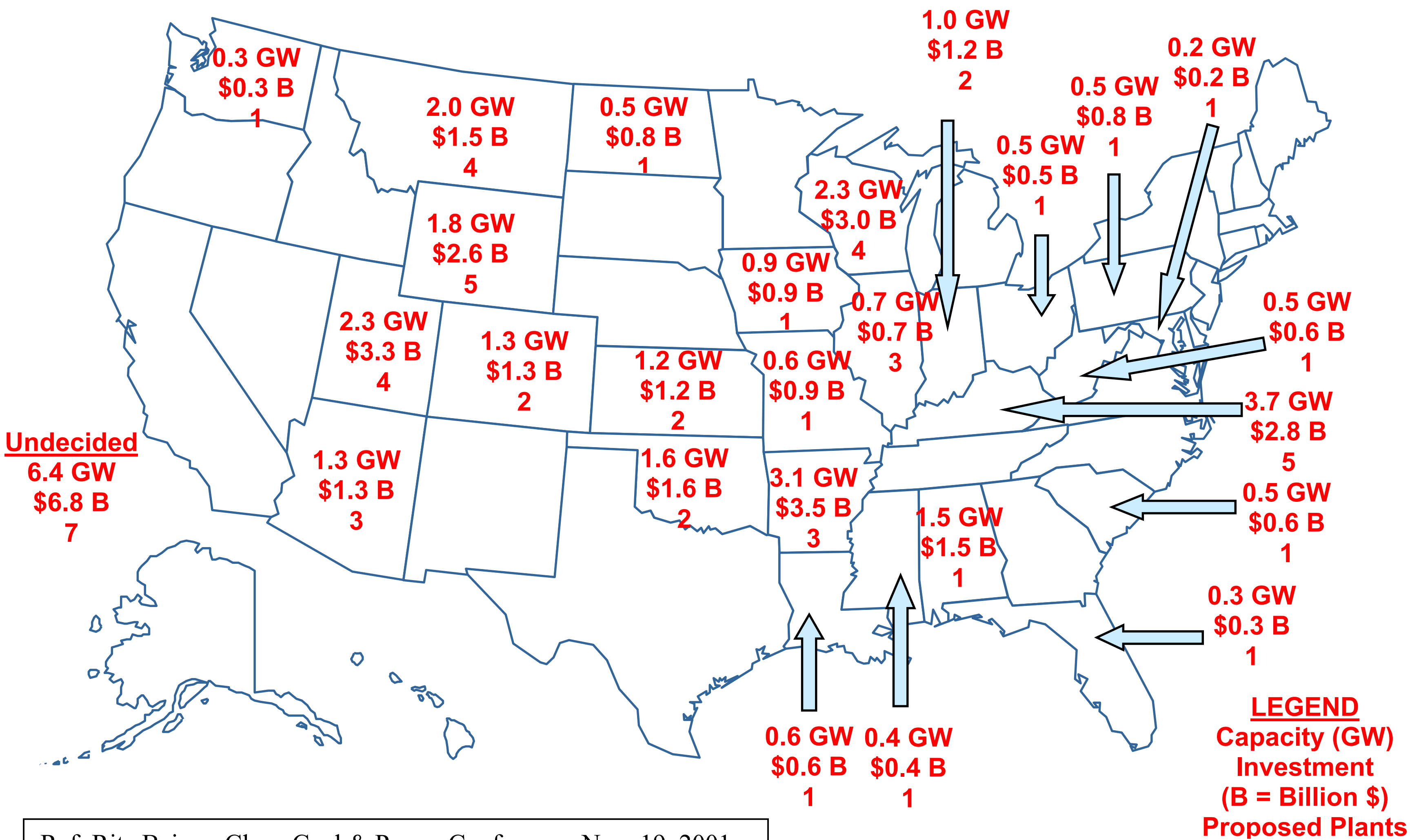
Gasification of petroleum coke not only generates the steam, power and hydrogen that the refineries use, but it has the synergistic ability to eliminate the need to sell or dispose of the low value petroleum coke. A typical refinery has twice the volume of petroleum coke needed for gasification to supply its hydrogen needs, providing an excess for potential power generation and export while at the same time supplying a significant production of steam for the process plant.

---

[1] Bajura, Rita, “Clean Coal Power Initiative”, presented at the Clean Coal Power Workshop, Pittsburgh, Pa., Sept. 28, 2001.
[2] Ziesmer, Ben, “World Petroleum Coke Market Trends”, presented at the Gasification Technologies Conference, San Francisco, CA, Oct. 9, 2000.

Many New Coal Plants Announced

59 Plants & 36 GW Proposed at $39 Billion Investment



Ref: Rita Bajura, Clean Coal & Power Conference, Nov. 19, 2001

NETL New Coal Capacity Database

In the U.S., petroleum coke production is over 100,000 tons per day[3] – enough petroleum coke for 50 Wabash River sized plants or 20 of the larger facilities outline in this study. However, a good portion of this production is geographically dispersed or committed to other markets. It seems reasonable that 5 to 7 gasification coproduction plants can be developed domestically in the time frames anticipated in this study.

VII.2 Environmental Drivers

Gasification technology is expected to have a significant share of the future power market because

1. It is a "clean", environmentally friendly process,
2. It can accept various low-cost feedstocks, such as petroleum coke, biomass and wastes,
3. Syngas, the intermediate product, is a versatile feedstock for the production of various chemicals, such as hydrogen, methanol, acetic acid, etc.,
4. It can capture most of the pollutants, such as sulfur, carbon dioxide, hydrocarbons, and particulates, and
5. It has the potential to achieve 60% or higher thermal efficiency for power production by integration with fuel cells, advanced turbines, and hydrogen-fed turbines.

Global Energy has demonstrated the flexibility of their gasifier to handle both coal and petroleum coke. The Subtask 1.3, Subtask 1.3 Next Plant, and Subtask 1.5 results confirm that low cost petroleum coke can improve the overall economics of a gasification project. Furthermore, these results also demonstrate that coproduction of hydrogen and power may enhance the overall economic of the project.

Recently, there have been changes in the power market that are favorable to the use of IGCC plants for power generation. The deregulation of the utility industry brings a different set of power plant owners who may be eager to ally with non-utility plant owners in developing cogeneration projects. These owners are more comfortable with the complexity of IGCC plants. The use of low value feedstocks and the synergistic effects of coproducing chemicals and exporting steam have improved the overall economics of IGCC projects. As more of these cogeneration plants are built and operated, the capital and operating costs of the IGCC plant component will drop. Project financing also will be more readily available as confidence on the overall plant performance increases due to the more positive operating experience. Some of the most recent projects include the Delaware Clean Energy Project, ExxonMobil Baytown Syngas Project, and Farmland Industries Petrochemical Plant.

Another major driver for the gasification technology is its ability to reduce the emission of pollutants. In the near-term, gasification plants can capture more than 99% of the sulfur in the feed. Particulate and NOx emissions are equal to or less than those from conventional pulverized coal plants and natural gas combined cycle plants.

In a carbon constrained environment, gasification will be the preferred power generating technology because it can produce a concentrated carbon dioxide stream that can facilitate more efficient CO_2 capture. If the syngas is treated in a water gas shift (WGS) unit, each unit of carbon monoxide is converted by reaction with water into one unit of carbon dioxide

[3] Gray, David and Tomlinson, Glen, "Market Potential of Gasification in the U.S. Refining Industry", presented at the Gasification Technology Council Spring Meeting, Williamsbur, VA, April 27-28, 2000.

and hydrogen. If a coal-water slurry fed gasifier is employed (similar to that of Global Energy's E-GAS^{TM} gasifier), the effluent stream from the CO shift unit will contain about 49 mole % hydrogen and 42 mole % carbon dioxide.

The thermal efficiency of an IGCC plant can be improved by integration with an advanced gas turbine or fuel cells. The syngas or hydrogen stream from the IGCC plant is an excellent feedstock for a fuel cell stack. Such integrated gasification/fuel cell plant combinations are expected to have high thermal efficiencies of at least 60%.

In summary, gasification technology is an attractive choice for utilizing today's low cost feedstocks to produce clean power. It has a high thermal efficiency. Furthermore, it can easily be modified to meet the challenges from future regulations related to greenhouse gas emissions.

VII.3 Future Applications

The results of this study by Bechtel, Global Energy and Nexant provide a firm basis for definition of the IGCC and IGCP plant performance and cost basis needed for development of additional expansion into these markets. The results of the last two years of this cooperative effort, beginning with the solid database of the Wabash River construction cost, has produced profiles of competitive gasification based facilities for several markets and multiple timeframes.

The strongest drivers for the implementation of gasification are its inherent environmental performance and efficiency for utilization of solid fuels. These factors make it a viable alternative to the conventional coal combustion technologies that have historically been more widely utilized.

In the near term, for plants starting up in the 2005-2008 time period, the technology has been demonstrated and commercialized. The only "tweaks" to the existing technologies utilized in the study are the addition of the cyclone in the dry char filtration system (demonstrated in Europe) and the enhanced operation of the second stage of the E-GAS^{TM} gasifier by using full slurry quench for second stage temperature control as discussed in the study. Optimization of the combustion turbine NOx performance will be beneficial in some geographic locations as well.

Achievement of the installed cost goals through application of the optimization techniques shown in the study will be realized in the first plants built, and they will provide a demonstrated basis for additional projects. Expanding the confidence of installed cost numbers gained in the study will bring additional commitments from other prospective customers. Operating cost levels already have been demonstrated to a great extent at Wabash River.

The importance of the petroleum coke gasification applications to this generation of projects cannot be underemphasized. These projects, utilizing low cost petroleum coke as a feedstock and producing higher value products such as steam and hydrogen, will be the first to enter the marketplace since several of these have already started development. Wabash River already has demonstrated petroleum coke gasification at a commercial scale. The new plants will help demonstrate the integration with petroleum refineries and the attainment of the necessary operating levels required to support refinery operations. New standards for capital costs and operating costs will be set as well. These petroleum coke plants, which will be the leaders of the next generation of gasification applications, will support the technology and confirm the economics for the coal fueled IGCC power plants which will follow them.

The economics of the coal-to-power IGCC facilities may be enhanced by federal and state incentive programs which are aimed at increasing the fuel diversity of our power generation resources. Such programs could speed the wider application of IGCC technologies in a market currently dominated by the existing coal baseload fleet and the natural gas combined cycle intermediate and peaking plants.

Further in the future, the largest part of the potential gasification market comes as the bulk of the aging U.S. coal fired generation fleet eventually must be retired. New IGCC plants utilizing the “H class” combustion turbine and other advancements discussed in this report will compose part of these replacements bringing the environmental performance of the gasification processes into the fleet. Additional demonstration work may be required to ensure the financability of these projects.

Most of the basis, however, will have been demonstrated either in the Wabash River generation plants or in the coming generation of plants. These projects on bituminous coal and petroleum coke will have refined the technology application, once again bridging the way to even more widespread applications.

The following developments will be key to the long term commercialization of gasification technologies and integration of this environmentally superior solid fuels technology into the power plant fleet:

- Development of the “H class” combustion turbine for syngas applications
- Demonstration of warm gas clean-up technologies (e.g., SCOHS)
- Gasifier advancements including slurry feed vaporization in the second stage
- Additional optimization work for the lower rank, sub-bituminous and lignite coals that were not evaluated as part of this study.
- Development and implementation of large capacity fuel cells; optimization of the integration of gasification with advanced fuel cell processes
- Further advances in Fischer-Tropsch technology or other gas-to-liquids technologies for the production of liquid transportation fuels from coal
- Progress toward the hydrogen economy

The gasification plant concepts developed in this study for the Subtask 1.3 Next Plant (Optimized Petroleum Coke IGCC Coproduction Plant) and the Subtask 1.6 1,000 MW coal power plant have immediate viability in today’s market. These plants can compete against most future cost projections for natural gas and power. The other, wider applications will be enhanced as other technologies develop. With these tools in hand, the United States can move closer to energy independence based on utilizing our domestic resources of coal and eliminating the export of petroleum coke.

Summary, Conclusions and Recommendations

VIII.1 Summary

Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly.

This study is concerned with the optimization of coal and petroleum coke gasification systems to reduce the cost of power and associated co products primarily by reducing the plant cost. It shows the potential of IGCC based systems to be competitive with, if not superior to, conventional combustion based power systems because of their higher efficiency, superior environmental performance, and competitive cost.

This is divided into nine basic subtasks. Subtasks 1.1 and 1.2 developed non-optimized designs for coal and coke IGCC power and coproduction plants. Subtasks 1.3 through 1.7 and 1.3 Next Plant developed optimized designs for coal and coke IGCC power and coproduction plants. Subtask 8 performed a review of warm gas cleanup systems. Subtask 1.9 documented the availability analysis study (and results) that was performed as part of the Value Improving Practices portion of the optimization efforts.

For each case, detailed process simulation models were developed providing elementally balanced mass and heat balances. From these balances, P&IDs, equipment sizes, line sizes, and plant layouts were developed for each case. Coupled with the actual Wabash River cost data, this information allowed detailed cost estimates to be developed with a low degree of uncertainty. This detailed information is confidential.

Subtask 1.1 started from the DOE sponsored Wabash River Coal Gasification Repowering Project (at Terre Haute, Indiana), to develop a design and mid-year 2000 cost estimate for a grass-roots plant equivalent to the Wabash River facility. This case represents the then current Wabash River plant and includes all the modifications and improvements that were made since the initial startup. The 452.6 MM mid-year 2000 dollar cost of the grass-roots plant (1,681 $/kW) was developed based on the actual construction cost of the Wabash River facility and subsequent modifications to provide a sound basis for the subsequent cases.[1]

Subtask 1.2 developed a non-optimized design, cost estimate, and economics for a Petroleum Coke IGCC Coproduction Plant processing 5,249 tpd of dry petroleum coke and producing about 79.4 MMscfd of hydrogen and 980,000 lb/hr of industrial-grade steam (750^{o}F/700 psig) in addition to 396 MW of export power. Also it produced 367 tpd of sulfur and 363 MMBtu/hr of low BTU fuel gas for the adjacent petroleum refinery. The plant is located on the U. S. Gulf Coast. It costs 993.2 MM mid-year 2000 dollars. The discounted cash flow analysis showed that this plant requires an export electric power price of about 43.4 $/MW-hr to produce a 12% after tax return on investment.

[1] All costs are mid-year 2000 costs. They are presented here to show the relative differences between the cases. Current cost estimates should be developed for any proposed application.

Subtasks 1.3 through 1.7 developed optimized designs for coal and petroleum coke IGCC plants. Value Improving Practices provided a structured approach to reducing the plant cost for the optimized designs. The use of VIPs outside of a specific project removes the limitations of schedule constraints and allows a more thorough examination of the ideas that were generated during the process. The Value Improving Practices team, which consisted of operating and maintenance personnel from the Wabash River plant, Global Energy's gasification experts, and Bechtel's engineers and construction specialists, examined all aspects of the proposed plant and generated almost 300 value engineering ideas. Those that were economically viable were incorporated into the optimized designs. Others are being developed for future applications which will lead to further cost reductions.

Subtask 1.3 and Subtask 1.3 Next Plant developed four optimized designs, cost estimates and economics for Petroleum Coke IGCC Coproduction Plants processing about 5,400 tpd of dry petroleum coke and producing about 80 MMscfd of hydrogen and 980,000 lb/hr of industrial-grade steam (750^{o}F/700 psig) in addition to electric power. The Subtask 1.3 Next plant processed 5,417 tpd of dry petroleum coke and produced 474 MW of export power and 373 tpd of sulfur. No low BTU fuel gas was exported to the refinery; instead it was used to make additional power.

These petroleum coke IGCC coproduction plants primarily differed in the amount of spare and replicated equipment they contained and the method of particulate removal from the syngas. The Subtask 1.3 plants used a dry cyclone followed by a wet scrubbing column for particulate removal, and the Subtask 1.3 Next Plant used a dry cyclone followed by a dry char filter system. The Subtask 1.3 Base Case was based on the Wabash River configuration and contained a spare reactor in each of the two gasification trains. The minimum cost case eliminated the spare reactors. The spare gasification train case added a spare gasification train to the minimum cost case. Availability and discounted cash flow analyses showed that the spare gasification train plant had the lowest required electric power price even though it had the highest plant cost at 812 MM mid-year 2000 dollars.

Based on the above results, the Subtask 1.3 Next Plant was developed containing a spare gasification train, the completely dry particulate removal system described above, and other improvements. The plant cost was reduced to 787 MM mid-year 2000 dollars. The discounted cash flow analysis showed that this plant can export electric power at about 30 $/MW-hr and still produce a 12% return on investment. This 13 $/MW-hr reduction from the Subtask 1.2 power price is a direct result of the effectiveness of the optimization techniques and Value Improving Practices that were used.

Subtask 1.4 developed a design, cost estimate, and economics for a future single-train Optimized Coal IGCC Power Plant. This plant processes 3,007 tpd of dry Illinois No. 6 coal and produces 416 MW of export power. It uses an advanced "G/H-class" combustion turbine that is expected to be available at the end of the decade. It cost 465 MM mid-year 2000 dollars (1,116 $/kW), and can dispatch power at 42.8 $/MW-hr while generating a 12% ROI. With the use of backup natural gas, the export power price can be reduced to 39.8 $/MW-hr.

Subtask 1.5 compared present day, single-train coal and petroleum coke fueled IGCC power plants highlighting the major differences between the designs, developing cost estimates, and doing a financial analysis for each case. Both plants use the General Electric 7FA+e combustion turbine and are basically are similar in design, but do contain differences. However, future IGCC developments for either fuel generally will benefit the other one. The Subtask 1.5A coal plant cost 375 MM mid-year 2000 dollars (1,318 $/kW) and requires a power selling price of 53.9 $/MW-hr for a 12% ROI without backup natural gas and 48.9 $/MW-hr with backup gas. The Subtask 1.5B coke plant cost 367 MM mid-year 2000 dollars (1,260 $/kW) and requires a power selling price of 43.9 $/MW-hr for a 12% ROI without backup natural gas and 40.6 $/MW-hr with backup gas. The major factor for the lower power price for the coke plant is the cheaper coke price. Both power prices are significantly lower than the 67.5 $/MW-hr required power selling price for the Subtask 1.1 Wabash River Greenfield Plant without backup natural gas.

Subtask 1.6 developed a current day optimized design, cost estimate and financial analysis for a nominal 1,000 MW coal fed IGCC power plant using four GE 7FA+e combustion turbines. The plant processes 9,266 tpd of dry Illinois No. 6 coal and generates 1,155 MW of export power. It cost 1,231 MM mid-year 2000 dollars (1,066 $/kW) and can export power at 44.4 $/MW-hr without natural gas backup while producing a 12% ROI. With backup natural gas, the required power price drops to 40.2 $/MW-hr which is almost as low as that of the future Subtask 1.4 single train plant.

Subtask 1.7 developed an optimized design, cost estimate and financial analysis for a single-train coal to hydrogen plant processing 3,007 tpd of dry Illinois No. 6 coal and producing 141 MMscfd of 99.0% chemical grade hydrogen. Sulfur production is 76.4 tpd. The plant costs 530 MM mid-year 2000 dollars and requires a hydrogen selling price of 2.70 $/Mscf to produce a 12% ROI. This is significantly higher than the hydrogen price of 1.30 $/Mscfd which was used in the financial analysis for the Subtask 1.3 cases and is based on a 2.60 $/MMBtu natural gas price. One advantage of a coal based hydrogen plant is that it provides a stable hydrogen cost that is disassociated from the volatile natural gas price.

Subtask 1.8 reviewed the status of warm gas clean-up technology as applicable to coal or coke fueled IGCC power and coproduction plants. The objective is to evaluate developing technologies that operate in the 300 to 750^{o}F temperature range, preferably closer to 750^{o}F, and to determine their potential economic benefit. No technologies were found to be better than the standard amine system currently in use. Selective catalytic oxidation of hydrogen sulfide systems (SCOHS) have the potential to be simple cost effective systems.

Subtask 1.9 developed a report describing the Value Improving Practices availability and reliability design optimization program. Starting from historic Wabash River Repowering Project data, this subtask discussed how the availability analysis and design considerations, such as the expected annual coke consumption, influenced plant performance and sparing philosophy.

Gasification is viewed as the environmentally superior process for power generation from coal. The Wabash River facility demonstrated the superior environmental performance of gasification in terms of SOx, NOx, and particulate emissions. In a carbon-constrained environment, the CO_2 easily can be captured for sequestration or other uses. Even without CO_2 capture, CO_2 emissions are minimized because gasification plants are more efficient. The future Subtask 1.4 plant has a thermal efficiency of 44.5% (HHV) compared to the 35% to 37% thermal efficiencies of conventional coal power plants. Compared to a 36% efficient conventional power plant, the Subtask 1.4 plant will generate 24% less CO_2 because it consumes 24% less coal. As gasification technology matures, further efficiency improvements (approaching 50% on an HHV basis) are expected whereas little, if any, improvement appears likely in conventional plants.

As natural gas and power prices increase and environmental constraints for coal fired generation tighten, coal IGCC will further penetrate the power market. As more coal and coke IGCC plants are built, further improvements can be expected which should lead to additional cost reductions that will make IGCC the preferred option for new base-load power plants.

In the near term, for plants starting up in the 2005-2008 time period, the E-GAS^{TM} technology has been demonstrated and commercialized. Achievement of the installed cost goals through application of the optimization techniques shown in the study will be realized in the first plants built, and they will provide a demonstrated basis for additional projects. Operating cost levels already have been demonstrated to a great extent at Wabash River.

Petroleum coke gasification projects will be the first to enter the marketplace since several of these have already started development. Wabash River has already demonstrated petroleum coke gasification at a commercial scale. The new plants will demonstrate the integration with petroleum refineries and the necessary reliability required to support refinery operations. New capital cost and operating cost standards will be set. Furthermore, they will support the technology and confirm the economics for the coal fueled IGCC power plants that will follow.

The gasification plant concepts developed in this study for the Subtask 1.3 Next Plant (Optimized Petroleum Coke IGCC Coproduction Plant) and the Subtask 1.6 1,000 MW coal power plant have immediate viability in today's market. These plants can compete against most future cost projections for natural gas and power. Other applications will develop as the technology matures.

The economics of coal-to-power IGCC facilities may be enhanced by federal and state incentive programs which are aimed at increasing the fuel diversity of our power generation resources. Such programs could speed the wider application of IGCC technologies in new facilities and promote the repowering of older plants. Additional demonstration work may be necessary to convince the financial community of the economic viability of IGCC facilities.

VIII.2 Conclusions

This study has shown that

- Optimization of IGCC plants has resulted in significant cost savings.
- Additional cost savings appear likely as some of the concepts developed in this study are researched, developed and implemented.
- The Value Improving Practices used in this study provided a structured method for reducing both the plant cost as well as the operating and maintenance costs.
- Substantial cost reductions can be obtained by optimization of the plant layout to reduce the plant size.
- Petroleum coke-fueled IGCC coproduction plants are economically competitive in today's economic environment.
- Power generation by gasification of coal is not yet competitive with coal combustion plants, but the gap has narrowed substantially. Further developments will make IGCC competitive.
- Petroleum coke- and coal-fueled IGCC power plants are very similar. There are differences, but the costs of the two plants are similar.

- Information from the design, construction and operation of petroleum coke gasification plants will further the development and commercialization of coal-fueled plants.
- Since the gasification block of an IGCC power plant has a lower availability than the gas turbine, the cost of electricity can be lowered by the use of backup natural gas to fire the gas turbine when syngas is unavailable.
- As natural gas prices increase, coal-fueled IGCC power plants will produce lower cost power than gas-fired combined cycle plants.

VIII.3 Recommendations

Technology development will be the key to the long-term commercialization of gasification technologies and integration of this environmentally superior solid fuels technology into the existing mix of power plants. The following areas are recommended for further development:

- Development of the “G/H-class” combustion turbine for syngas applications
- Gasifier advancements including slurry feed vaporization in the second stage
- Demonstration of warm gas clean-up technologies (e.g., SCOHS)
- Testing of advanced wet and dry filtration systems
- Additional optimization work for the lower rank, sub-bituminous and lignite coals
- Development and implementation of large capacity fuel cells; optimization of the integration of gasification with advanced fuel cell processes
- Further advances in Fischer-Tropsch technology or other gas-to-liquids technologies for the production of liquid transportation fuels from coal
- Develop a lower cost means of producing oxygen such as the ITM ceramic membrane system

With IGCC as a power generation option, the United States can move closer to energy independence based on utilizing our domestic resources of coal and eliminating the export of petroleum coke.

Chapter IX

Acknowledgements

The help, assistance, guidance, and support of the following individuals and organizations is hereby acknowledged.

The United States Department of Energy's National Energy Technology Laboratory (DOE/NETL) for their financial support

John Rockey of DOE/NETL for his inspiration, guidance and promotion of this study

Gary Stiegel of DOE/NETL for his ongoing support

The managements of Bechtel, Global Energy and Nexant for their backing and financial support

General Electric for their assistance with the performance of the combustion turbine

Praxair for their assistance with the performance of the air separation unit

UOP for their assistance with the performance of the PSA unit

Borsig, Callidus Technologies, Emtrol, Nooter, Svedala, USFilter, and other equipment manufactures and suppliers for their assistance with designs, performance specifications and cost quotations

Attachment A

ESTIMATED GE PG7241(FA) GAS TURBINE PERFORMANCE
(Received from Douglass Todd on June 19, 2000)

DOE IGCC Studies
ESTIMATED GE PG7241(FA) GAS TURBINE PERFORMANCE

	Units	Steam Diluent
SITE CONDITIONS:		
AMBIENT TEMPERATURE	°F	70
AMBIENT PRESSURE	psia	14.683
AMBIENT RELATIVE HUMIDITY	%	60
INLET PRESSURE DROP	In H2O	3.0
PERFORMANCE:		
GROSS GENERATOR OUTPUT	kW	210,000
HEAT CONSUMPTION (LHV)	MMBtu/h	1,795.0
HEAT RATE (LHV)	Btu/kWh	8,548
FUEL 1 CONDITIONS:		
COMPOSITION	%Vol	
CARBON MONOXIDE		48.08
CARBON DIOXIDE		9.08
HYDROGEN		19.26
WATER		19.02
NITROGEN		0.89
METHANE		2.62
ARGON		1.05
HYDROGEN SULFIDE		0.00
CARBONYL SULFIDE		0.00
LHV	Btu/Lb	3,917.0
	Btu/Scf	231.4
FUEL GAS FLOWRATE	lb/s	127.3
PRESSURE	psia	365
TEMPERATURE	°F	530
NOx DILUENT INJECTION CONDITIONS:		
COMPOSITION	%Vol	
CARBON DIOXIDE		
NITROGEN		
WATER		100.00
FLOWRATE	lb/s	70.3
PRESSURE	psia	350
TEMPERATURE	°F	550
EQUIVALENT LHV:		
LHV	Btu/Lb	2,524
	Btu/Scf	137.3
EXHAUST GAS CONDITIONS:		
EXHAUST GAS FLOW	lb/s	1,106.5
EXHAUST GAS TEMPERATURE	°F	1,097.5
EXHAUST GAS COMPOSITION	%Vol	
CARBON DIOXIDE		8.66
ARGON		0.89
NITROGEN		62.07
OXYGEN		11.00
WATER		17.38
EXHAUST PRESSURE DROP	In H2O	14.0
NOx (Thermal)	ppmvd @ 15% O_2	<10

B. Derboven
6/15/2000 Rev 1

44 Montgomery Street, Suite 4100
San Francisco, CA 94104-4814
tel: +1 415 912 2100
fax: +1 415 981 9744
email: info@nexant.com

www.nexant.com

Prepared for:
United States
Department of Energy
National Energy
Technology Laboratory
Contract No. DE-AC26-99FT40342

Gasification Plant Cost and Performance Optimization
Task 1 Topical Report
IGCC Plant Cost Optimization

Volume 2
Appendices A through E

Submitted By:

BECHTEL

GLOBAL ENERGY

Nexant

MAY 2002

U. S. Department of Energy
National Energy Technology Laboratory (NETL)

Gasification Plant Cost and Performance Optimization
(Contract No. DE-AC26-99FT40342)

Task 1 Topical Report
IGCC Plant Cost Optimization

Volume 2 of 3
Appendices A through E

May 2002

Work Performed from September 1999 to January 2002

Prepared by:

Bechtel Corporation
3000 Post Oak Boulevard
Houston, TX 77056

Global Energy Inc.
Suite 3800
1000 Louisiana Street
Houston, TX 77002

Nexant Inc.
Suite 4100
44 Montgomery St.
San Francisco, CA 94104

Appendix A - Subtask 1.1

Wabash River Greenfield Plant

Introduction

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy (DOE) to promote energy production from fossil fuels in the 21st century. It will integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. It will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 includes plans to give integrated gasification combined cycle (IGCC) systems a major role for the continued use of solid fossil fuels. Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly to build and operate. The goal of this study is to improve the net present value (NPV) of gasification projects by optimizing plant performance, capital cost, and operating costs. The key benefit of doing this methodical cost optimization process off-line is that it removes the schedule constraints associated with project development that tend to inhibit innovation and implementation of new ideas.

In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel Technology & Consulting Company) and Global Energy, Inc. (which recently acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the Destec Gasification Process) a contract to optimize IGCC plant performance.[1] Task 1 of this contract will optimize two IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Task 2 will optimize two different IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of liquid transportation fuels, and (2) coal gasification for electric power with the coproduction of liquid transportation fuels. Task 3 will develop conceptual designs and projected costs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

This appendix describes the results of Subtask 1.1, the Wabash River Greenfield Plant, which will be the basis for the following subtasks.

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion

[1] Contract No. DE-AC26-99FT40342, "Gasification Plant Cost and Performance Optimization"

turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[2] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrates a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[3,4] However, the first year of operation resulted in only a 20% capacity factor, with over one half of the outage time being attributable to the dry char particulate removal system where frequent failures of the ceramic candle filters were experienced. The facility has switched to operation with metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility for the site. Additionally, two successful tests using petroleum coke including one from a refinery processing Mayan crude were completed in November 1997 and September 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria. The results of the petroleum coke tests have been previously described.[5]

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.999 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing). The repowering project has demonstrated the ability to run at full

---

[2] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"
[3] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.
[4] Topical Report Number 20, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, September 2000
[5] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

load capability (250 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the Project, with a demonstrated heat rate of under 9,000 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-Gas Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

Description of the Wabash River Coal Gasification Repowering Project

A pictorial schematic diagram of the E-Gas™ process, as implemented at the Wabash River Repowering Project, is shown in Figure 1. Coal is ground in a rod mill along with treated water and slag fines recycled from the gasifier. Ninety-five percent oxygen from the air separation unit (ASU) is compressed and fed to the gasifier along with the coal.

The E-Gas™ gasifier has two stages: a slagging first stage and an entrained-flow, non-slagging second stage. In the first stage, the fuel slurry is partially combusted with oxygenat nominal conditions of 2,600°F and 400 psia. The oxygen and slurry are fed into the first stage through two opposed mixing nozzles of proprietary design. The oxygen feed rate is controlled to maintain the gasification temperature above the ash fusion point. Fluxes may be added prior to the grinding stage to ensure that the slag is fluid at the first-stage temperature. Molten slag flows to the bottom of the gasifier, where it is quenched and then removed for sale of disposal. The gasifier is capable of processing petroleum coke as well as a variety of coals.

In the E-Gas™ gasifier, the slurry feed is almost completely converted to a syngas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the feed is converted to hydrogen sulfide along with small amounts of carbonyl sulfide (COS). The nitrogen in the coal is converted to ammonia. In the second stage, additional slurry without any additional oxygen is injected and undergoes devolatization and pyrolysis. These endothermic reactions cool the syngas to approximately 1900°F and increase its heating value because of the nature of the products that are formed.

The hot syngas is cooled to approximately 700°F in the syngas cooler which generates 1600 psia steam. The cooled syngas is sent to a filter vessel containing porous candle filters that remover over 99.9% of the particulates which are recycled back to the gasifier via a proprietary pneumatic conveyance system. The filtered syngas is further cooled and then water scrubbed to remove the remaining particulates, chlorides, and volatile trace metals before going to the COS hydrolysis unit where the COS is converted to hydrogen sulfide.

The syngas is then cooled to 100°F in the low temperature heat recovery unit. The cooled syngas is sent to the acid gas removal system where most of the hydrogen sulfide and some carbon dioxide are removed. The cleaned syngas is then moisturized, superheated, and sent to the combustion turbine. The recovered acid gases are sent to the sulfur recovery unit that produces 99.999% pure sulfur. Sulfur recovery is greater than 98%.

The preheated moisturized syngas and compressed air are sent to the combustion turbine that is coupled to an air compressor. Hot exhaust gas from the turbine is sent to the heat recovery steam generator (HRSG), which superheats the 1600 psia high pressure steam from the syngas cooler and generates additional steam. The superheated steam, two-thirds of which has been generated in the syngas cooler, is sent to the pre-existing Westinghouse steam turbine. The steam turbine system contains high pressure, intermediate pressure, and low pressure power turbines and a generator. The intermediate pressure steam leaving the high pressure turbine is reheated before being sent to the intermediate pressure turbine. The steam leaving the low pressure turbine exhausts to the surface condenser.

More complete descriptions of the Wabash River Repowering Project are available in the DOE Topical Reports (references 3 and 4), the project final report and the DOE assessment of the project.[6,7]

The Wabash River Greenfield Project Plant

The gasification optimization work began with reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that Wabash River project design was transformed into a greenfield IGCC plant design to be used as the basis for developing the designs for the Subtask 1.2 Petroleum Coke IGCC Coproduction Plant and the subsequent optimized coal and coke power and coproduction plant designs.

Since one major focus of this study is the optimization of the gasification plant costs, the following three-stage cost estimating methodology was employed to develop a current year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project, were adjusted for unusual circumstances and escalated to today's values. The costs of any equipment and materials that were not part of the Wabash River project (such as existing facilities), but are required, were added the cost database.
- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Major pieces of equipment that required modifications during the demonstration period were incorporated, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. Bechtel's Multi-Project Acquisition Group (MPAG) worked with manufacturers, fabricators, and suppliers with whom current procurement agreements have been established to provide the most cost-effective

[6] Global Energy, Inc. "Wabash River Coal Gasification Repowering Project – Final Report," September 2000.
[7] DOE/NETL-2002/1164, "Wabash River Coal Gasification Repowering Project: A DOE Assessment," January 2002.

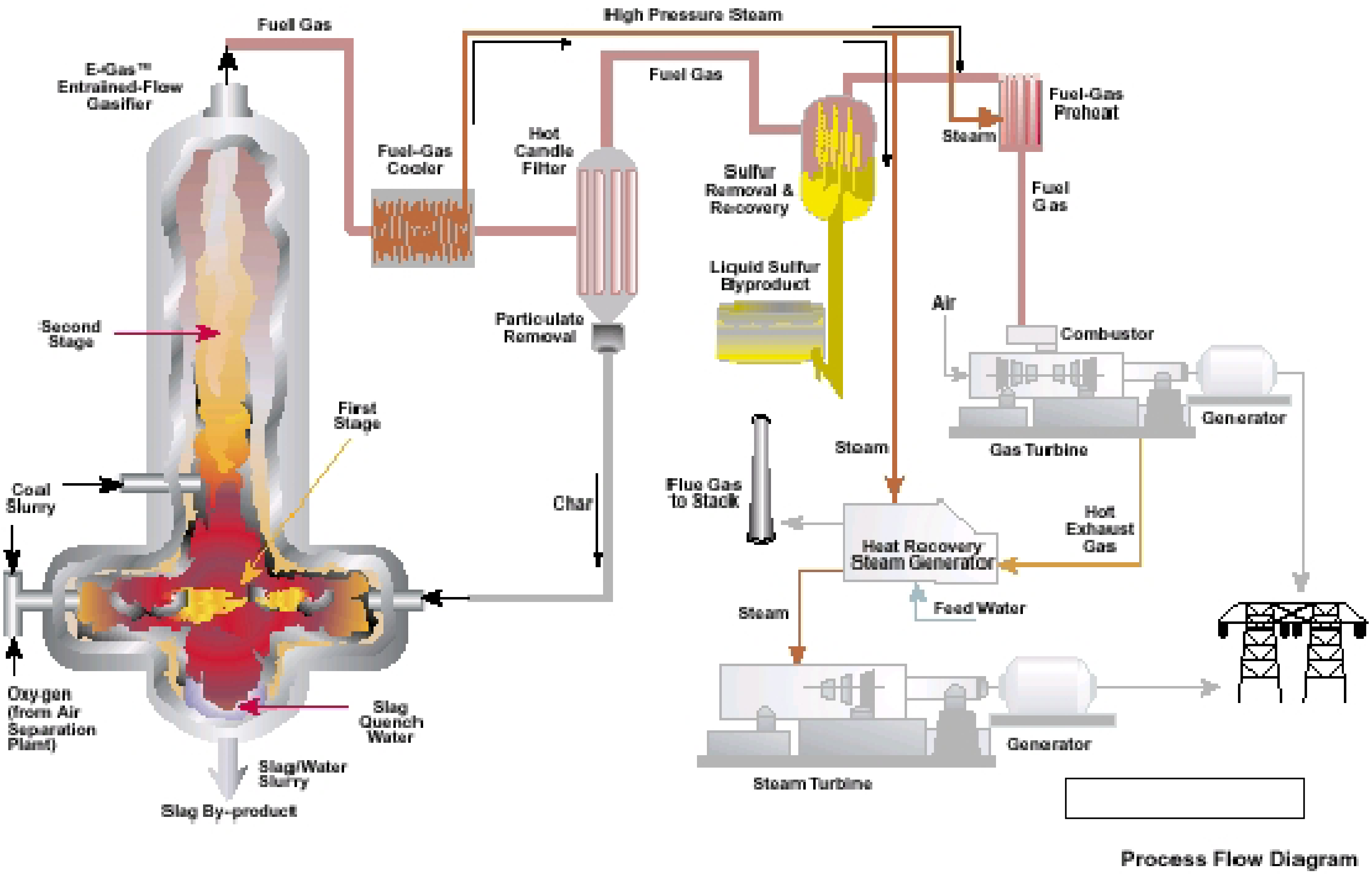
pricing. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities to provide a basis for evaluating future changes. This tool enables the study team to make changes in plot plan layout, process improvements, equipment sizes, structural support, etc. and determine the effect on the bulk material requirements.

- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Further evaluation of gasification technologies and other energy related process plants require a standard methodology for estimating the capital costs. The format for this estimating tool based on historical data, escalation indices and vendor quotes was developed and will be employed on subsequent tasks in this study and for future project development activities.

The following Subtask 1.1 (Appendix A) contains a more detailed description, and the design and cost information for the Subtask 1.1 Wabash River Greenfield Plant.

Figure 1

Pictorial Schematic Diagram of the Wabash River Repowering Project



Appendix A

Subtask 1.1 (Appendix A)

Wabash River Greenfield Plant

Subtask 1.1 (Appendix A)
Table of Contents

Figures

Subtask 1.1 (Appendix A)

Subtask 1.1 – Wabash River Greenfield Plant

A.1 Introduction

The primary objectives of Task 1 are to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operating experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

This appendix summarizes the results of Subtask 1.1. The scope of the Subtask 1.1 is to create a data base for the Wabash River project design and cost data, and to move the IGCC plant to a greenfield site. It contains the following design and cost information for the Wabash River Greenfield Plant:

- The design basis
- A block flow diagram
- A plant description
- An overall site plan of the IGCC power plant
- An artist's view of the plant
- An overall material, energy, and utility balance
- A plant performance summary
- An environmental emissions summary
- A major equipment list
- A project schedule
- A capital cost summary

The design information listed above will be the starting point to develop the design and cost estimate for Subtask 1.2, the non-optimized petroleum coke IGCC Coproduction Plant, and will be compared to the future Optimized Coal IGCC Power Plant that will be developed in Subtask 1.4.

The following sections describe the results of Subtask 1.1, the design and cost estimate for the Wabash River Greenfield Power Plant.

Section A.2 contains the design basis for the IGCC power plant. Section A.3 contains descriptions of the various sections of the plant. Section A.4 summarizes the overall plant performance. Section A.5 contains a listing of the major pieces of equipment within the plant. Section A.6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the Wabash River Greenfield Power Plant.

A.2.1 Capacity

The plant will process a nominal 2,500 TPD of Illinois No. 6 coal to produce syngas that will fully load a GE 7FA gas turbine at 59° F ambient, 60% relative humidity and 14.43 psia.

A.2.2 Site Conditions

Location	Typical Mid-Western State
Elevation, ft	500
Air Temperature	
Maximum, °F	93
Annual Average, °F	59
Minimum, °F	-20
Summer Wet Bulb, °F	70
Relative Humidity, %	60
Barometric Pressure, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

A.2.3 Coal

Type	Illinois No. 6	
	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,495
Analysis, wt%		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

A.2.4 Water

Cations	mg/L	As equivalent ppm of CaCO3
Aluminum	0.006	0.033
Arsenic	0.002	

Barium	0.055	0.040
Boron	0.154	
Calcium	74.0	185
Chromium	0.005	
Copper	0.002	0.003
Iron	0.028	0.050
Lead	<0.001	0.000
Lithium	0.006	
Magnesium	26.0	107.1
Manganese	0.009	0.016
Molybdenum	0.008	
Potassium	4.8	6.1
Sodium	33.0	71.9
Selenium	<0.001	
Strontium	0.297	0.339
Vanadium	0.010	
Zinc	0.008	0.012
Sodium (add to balance)		
Total Cations		371

Anions	mg/L	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	245.0	200.9
Chloride	44.0	62.0
Sulfide	79.0	82.2
Nitrate - Nitrogen	4.88	4.0
Phosphorus	0.538	4.482
Fluoride	0.25	0.665
Chloride (add to balance)	12.0	16.9
Total Anions		371

Weak Ions	mg/L	As equivalent ppm of CaCO3
Ammonia Nitrogen	0.132	
Dissolved Silica	7.1	

Other Characteristics	mg/L	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	419	
Standard Conductivity	671	
Total Alkalinity		201
Total Hardness		290
Total Organic Carbon	4 to 11.2	
Turbidity	8 to 100	
PH	7.6 to 8.4	
Total Nitrogen	6.1	
Total Suspended Solids	23 to 336	

A.3 Plant Description

A.3.1 Block Flow Diagram

The Wabash River Greenfield Plant design is based on the current design of the Wabash River plant and consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier/High Temperature Heat Recovery(HTHR)/Dry Char Filtration
    - Sulfur Removal
    - Sulfur Recovery
- Air Separation Unit (ASU)
- Power Block
    - Gas Turbine (GT)/Heat recovery Steam Generator (HRSG)
    - Steam Turbine Generator(STG)/Auxiliary Equipment
- Balance of Plant

Figure A1 is a block flow diagram of the above process blocks and subsystems of the Wabash River Greenfield Plant.

A.3.2 General Description

The plant is divided into the five distinct areas.

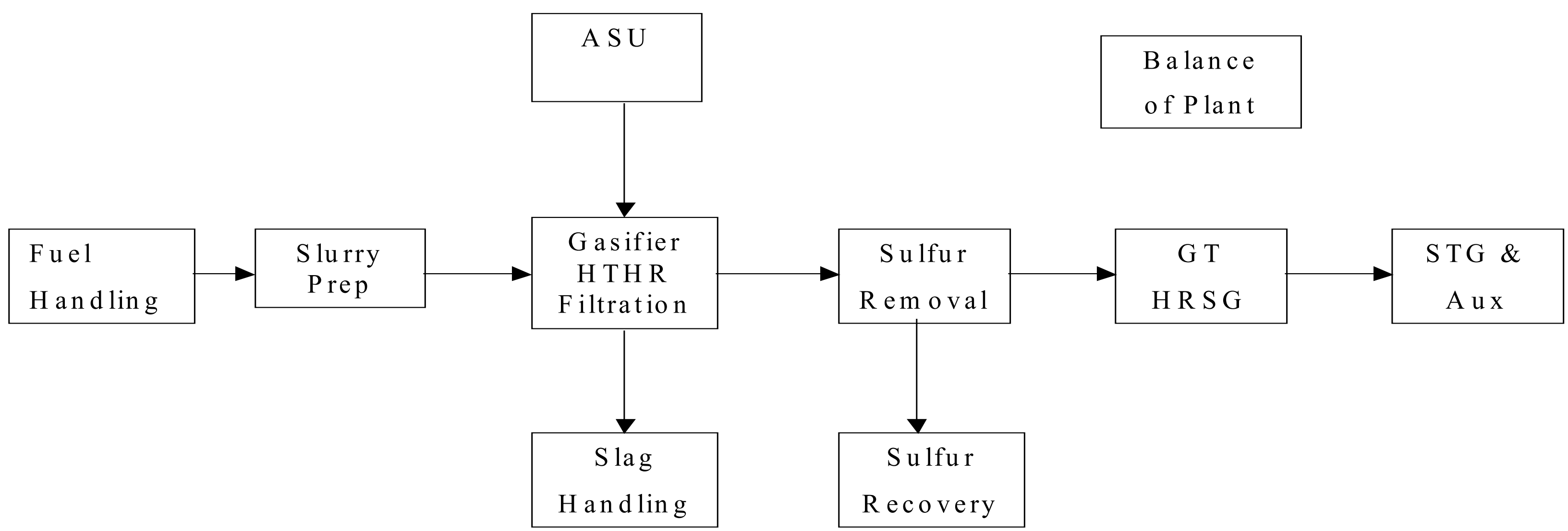
- Fuel Handling Unit
- Coal Gasification Plant
- Air Separation Unit
- Power Block
- Balance of Plant

Section A.3.3 describes the additional fuel handling facilities required for a greenfield site from unloading to on site storage and conveying to the gasification plant.

Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two stage entrained flow gasifier to convert coal to syngas. The greenfield plant includes a number of process units to remove impurities in the syngas. These process units are essentially the same as those of the Wabash River Repowering plant.

Figure A1

WABASH RIVER GREENFIELD PLANT BLOCK FLOW DIAGRAM



Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95 percent purity oxygen stream is produced as the oxidant for the gasifier. The design is based on the Wabash River Plant ASU.

Section A.3.6 describes the power block, which consists of a General Electric Frame 7FA combustion turbine with generator similar to the Wabash River gas turbine. A new reheat and condensing steam turbine with generator replaces the repowered steam turbine at the Wabash River plant.

Section A.3.7 describes the balance of plant (BOP). The BOP portion of the IGCC plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Wabash River Greenfield Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were drawn by the Comet Model.

A.3.3 AREA 100 - Fuel Handling

The coal handling system provides the means to receive, unload, store, reclaim, and convey coal to the storage facility. Coal is delivered to the site by rail and transferred to the gasification area through the coal unloading system to the crusher house. Coal also can be delivered by truck and dumped directly onto the coal pile when train deliveries are not available.

Coal is transferred from the crusher house to the active coal storage pile by transfer belt conveyors. Coal is reclaimed from the active coal storage pile to the gasification plant coal silo by variable rate feeder-breakers and the reclaim belt conveyors.

A.3.4 Coal Gasification Process

The coal gasification plant consists of several subsystems including coal slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur removal units. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 - Coal Slurry Preparation

Coal slurry feed for the gasification plant is produced by wet grinding in a rod mill. Coal is delivered by conveyor into the rod mill feed hopper. In order to produce the desired slurry solids concentration, coal is fed to the rod mill with water that is recycled from other areas of the gasification plant. Prepared slurry is stored in an agitated tank.

All tanks, drums, and other areas of potential atmosphere exposure of the product slurry or recycled water are covered and vented into the tank vent collection system for vapor emission control.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 AREA 300 – Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-GAS™ Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a horizontal refractory lined vessel into which oxygen and preheated coal slurry are atomized via opposing mixer nozzles. The coal slurry, recycle solids, and oxygen are fed in partial combustion quantities at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coal is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide and water. Sulfur in the coal is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both are easily removed by downstream processing.

Mineral matter in the coal forms a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthetic gas generated in the first stage flows up from the horizontal section into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which additional coal slurry is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This additional coal feed serves to lower the temperature of the gas exiting the first stage by the endothermic nature of the equilibrium reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by the addition of syngas from the syngas recycle compressor. No oxygen is introduced into the second stage.

The gas and entrained particulate matter exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

The raw gas leaving the high temperature heat recovery unit passes through a barrier filter unit to remove particulates. The recovered particulates are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir in the top of the bin and goes to a settler in which the remaining slag fines are settled. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank and a water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

The particulate-free gas then passes through a water scrubber to remove water-soluble contaminants from the syngas.

The syngas then is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a single train without backup sour water feed storage.

A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam-stripping at a lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA solution accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiencies.

A.3.4.5 AREA 420 – Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

The ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold box at moderate pressure and is then compressed in a centrifugal compressor and delivered to the gasifier.

A nitrogen tank with a steam vaporizer provides gaseous nitrogen. This tank also serves as a transfer and buffer vessel for normal gaseous production.

A.3.6 Power Block

The major components of the power block include the gas turbine (GT), heat recovery steam generator (HRSG), steam turbine (ST), and numerous supporting facilities.

A.3.6.1 AREA 500 - Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and Stack

The gas turbine is a General Electric 7FA, nominal 192 MW unit. The GT utilizes fuel moisturization and steam injection for $NO_{\times}$ emissions control. Combustion exhaust gases are routed to the HRSG and stack. Number 2 fuel oil is used as back-up fuel for the gas turbine startup, shutdown, and short duration transients in syngas supply.

The HRSG receives GT exhaust gases and generator steam at the main steam and reheat steam energy levels. It generates high pressure (HP) steam and provides condensate heating for both the combined cycle and the gasification facilities.

The HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSG boiler includes a steam drum for proper steam purity and to reduce surge during cold start. Large down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

The stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 - Steam Turbine (ST)

The reheat, condensing turbine includes an integrated HP/IP opposed flow section and a double flow LP section. Turbine exhaust steam is condensed in a surface condenser. The reheat design ensures high thermal efficiency and excellent reliability.

A.3.6.3 Power Delivery System

The power delivery system includes the GT's generator output, at 18 kilovolts (kV), connected through a generator breaker to the main power step-up transformer.

Two auxiliary transformers are connected between the generator breaker and the step-up transformer. One supplies the power block auxiliary equipment loads at 4.16kV. The second auxiliary transformer supplies the gasification plant loads at 13.8 kV. A new emergency shutdown transformer was added for the greenfield plant.

A.3.7 AREA 900 – Balance of Plant

A.3.7.1 Cooling Water System

The design includes two cooling water systems. One provides the cooling duty for the steam turbine surface condenser. A separate system provides the cooling duty for the air separation unit and equipment cooling throughout the gasification facility and power plant.

The major components of the cooling water system consist of a cooling tower and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. The cooling tower is a multi-cell mechanical draft tower, sized to provide the maximum required heat rejection for any startup or transient condition at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.7.2. Fresh Water Supply

River water is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it will be neutralized before discharge.

A.3.7.3 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the GT and HRSG area, and the switchyard.

Raw water from the nearby river is screened to remove debris and used as the supply to the system. A booster pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.7.4 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the waste water outfall system.

A.3.7.5 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The service air system consists of air compressors, air receivers, hose stations, and piping distribution for each unit.

The instrument air system consists of air receivers, air dryers, and a piping distribution system.

A.3.7.6 Incineration System

The tank vent stream is composed of primarily air purged through various in-process storage tanks and may contain very small amounts of acid gas. During process upsets of SRU, tail gas stream can be combined with the tank vent system before treatment in a high temperature incinerator. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide left in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.7.7 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.7.8 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC power plant is implemented using three separate digital Distributed Control Systems (DCS). The three separate systems are for ASU, gasification, and power block. The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or both; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, and the coal handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to the respective equipment; either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical GT, ST, and generator, and ASU control parameters.

This approach retains control of IGCC equipment used to transport the coal, control turbines and generators, and to support the ASU. Other balance of plant equipment such as air compressors, condenser vacuum pumps, and water treatment use either local PLCs, or contact and relay control cabinets to operate the respective equipment. All remaining plant components are exclusively controlled by the DCS including the HRSG, the gasifier, tail gas treatment, electrical distribution, and other power block and coal gasification support systems.

A.3.7.9 Buildings

The gasification area includes a building housing the gasification plant control room, office, training and other administration areas, and a warehouse/maintenance area. The building is heated and air-conditioned to provide a climate-controlled area for personnel and electrical control equipment.

Other buildings in the gasification area are used to house process equipment. These buildings have heating and ventilation.

A separate building houses the control room, maintenance area and offices for power plant personnel.

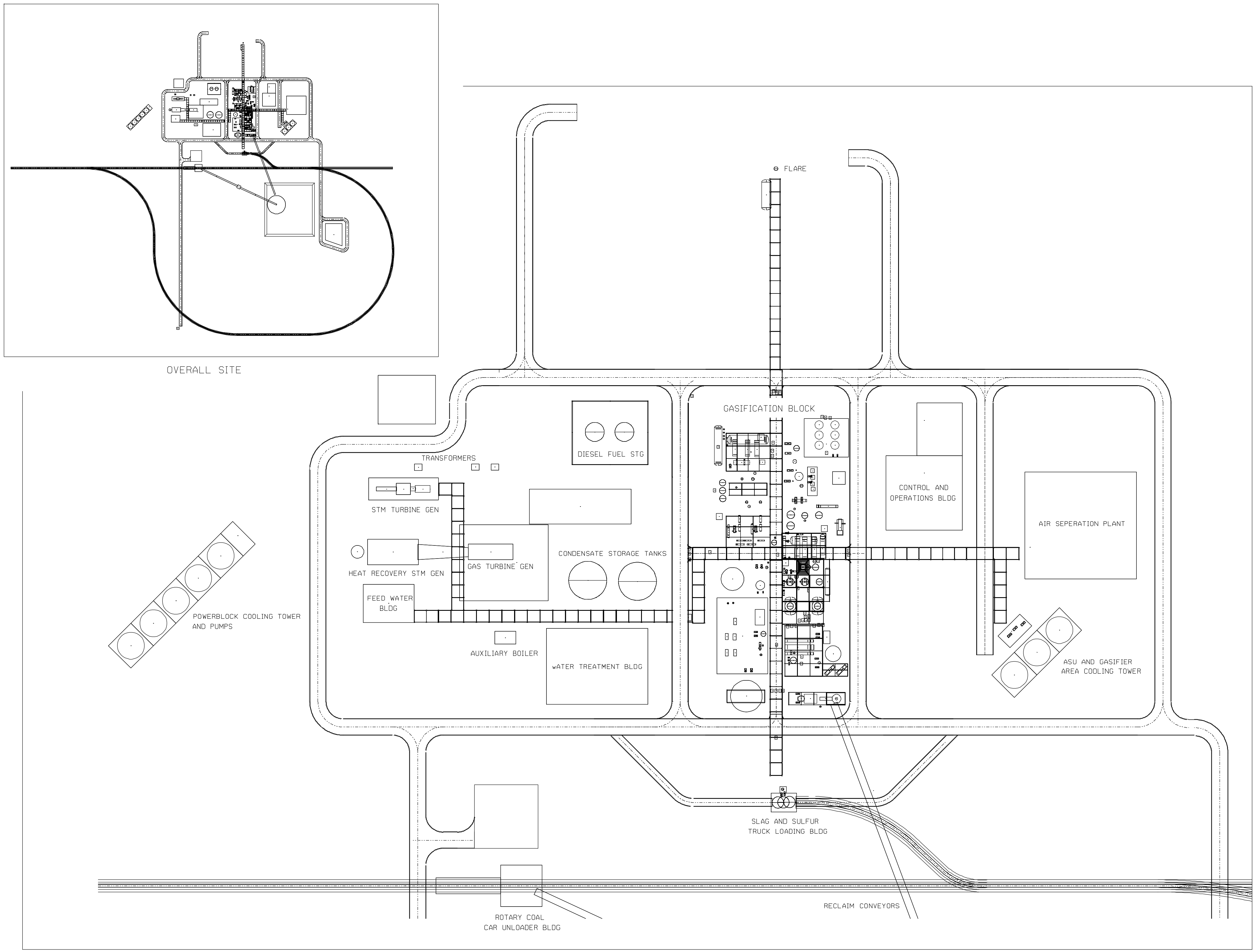
Process buildings for weather protection and for noise control are provided for the wastewater treatment tank area, rodmill, slurry pumps, slag handling equipment, slag dewatering tanks, circulating water pumps, air separation unit local controls, water treatment equipment, and boiler feedwater pumps, fire water pumps and compressors.

A.3.7.10 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the Wabash River Greenfield Plant



N

20 60 120 200
SCALE IN FEET

NO.	DATE	REVISIONS	BY	CHK	SLPV	PEM	CLIENT

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

WASBASH GREENFIELD
SUBTASK 1.1

JOB No: 24355-104

BECHTEL

GASIFICATION PLANT
SITE PLAN

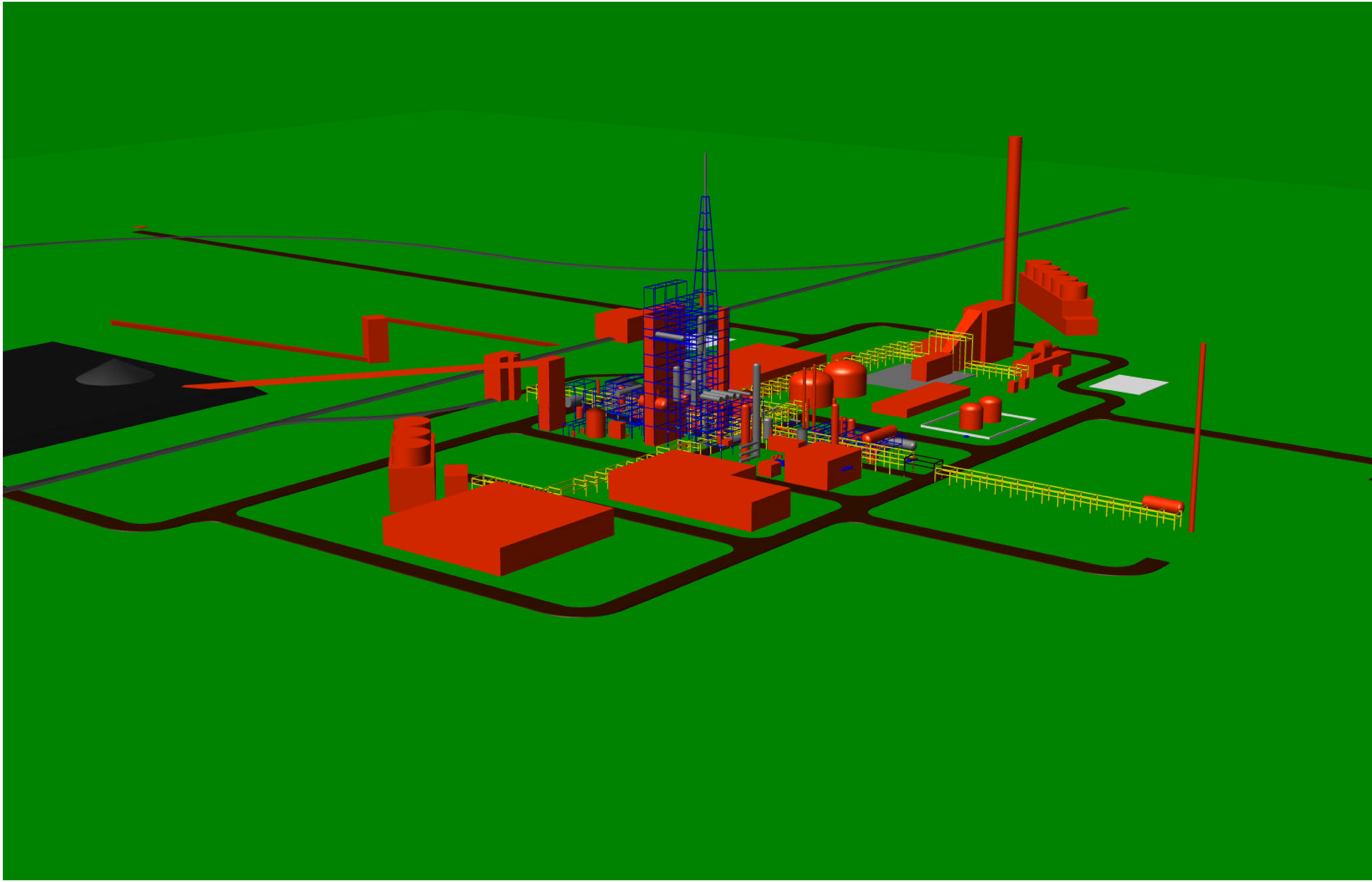
SCALE:

SK - 00001

REV.
A

Figure A3

Artist's Conception of the Wabash River Greenfield Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram showing key stream flows is shown in Figure A4, Wabash Greenfield IGCC Block Flow Diagram.

A.4.2 Performance Summary

Plant performance is based on the current Wabash River Repowering Project IGCC configuration including a GE 7FA gas turbine. Global Energy provided a heat and material balance for these facilities, using the design basis Illinois No. 6 coal. This information was then integrated with a new HRSG and reheat steam turbine. The GT Pro computer program was used to simulate combined cycle performance and plant integration.

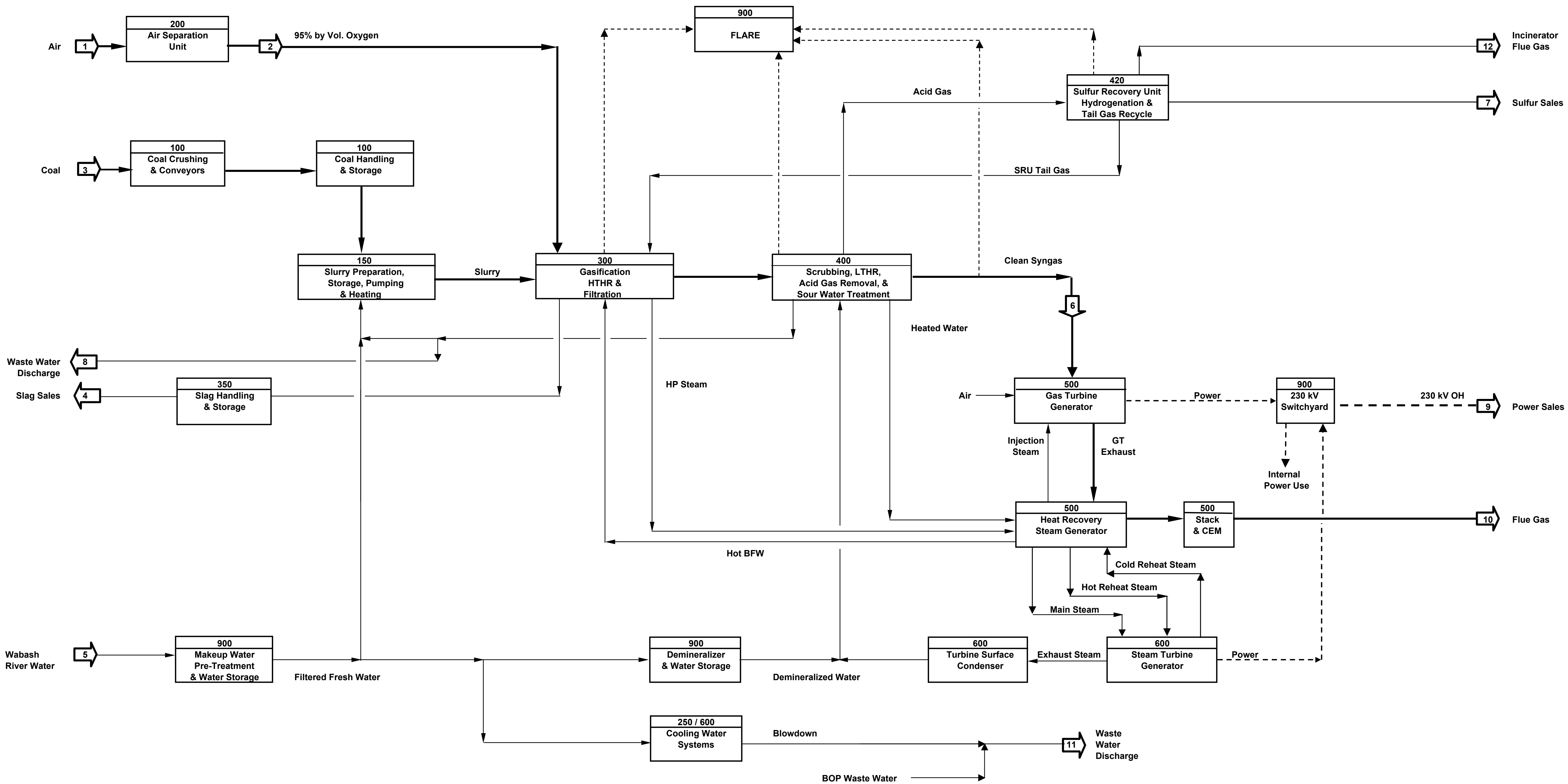
Table A1 summarizes the overall performance of the Wabash River Greenfield Plant.

Table A2 summarizes the emissions from the Wabash River Greenfield Plant.

Figure A4

Detailed Block Flow Diagram

of the Wabash River Greenfield Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 9,692 Tons/Day	Oxygen 2,130 Tons/Day	Coal 2,259 Tons/Day	Slag 356 Tons/Day	Water 1,140,500 Lb/Hr	Syngas 411,421 Lb/Hr	Sulfur 57 Tons/Day	Water 60,058 Lb/Hr	Power 269,300 kWe	Flue Gas 3,770,000 Lb/Hr	Water 318,000 Lb/Hr	Flue Gas 52,781 Lb/Hr									
Nominal Pressure - psig	Atmos.	540	NA	NA	50	320	NA	62	NA	Atmos.	Atmos.	Atmos.									
Temperature - F	59	240	NA	NA	70	530	NA	105	NA	238	NA	500									
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,370	NA	NA	NA	NA	NA	NA									
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,074	NA	NA	NA	NA	NA	NA									
Energy - MM HHV/Hr	NA	NA	2,400	NA	NA	1,798	NA	NA	NA	NA	NA	NA									
Energy - MM LHV/Hr	NA	NA	2,311	NA	NA	1,676	NA	NA	NA	NA	NA	NA									
Notes	Dry Basis		Dry Basis	15%Wtr.	2,281 GPM	to GT	Sales	120 GPM	230 kV		636 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.1

WABASH RIVER GREENFIELD PLANT

BLOCK FLOW DIAGRAM

File: Fig A4 1.1.xls February 20, 2002

Table A1

Performance Summary of the Wabash River Greenfield Plant

Ambient Temperature, °F	59
Coal Feed, as received, TPD	2,642
Dry Coal Feed to Gasifier, TPD	2,259
Total Fresh Water Consumption, gpm	2,790
Sulfur, Recovered, TPD	57
Slag Produced, TPD (15% moisture)	356
Total Oxygen Feed to the Gasifier, TPD	2,130
Heat Input to Gasifier, Btu/hr x 10^6	2,400
Cold Gas Efficiency at the Gas Turbine (HHV), %	76.9
Fuel Input to Gas Turbine, lb/hr	411,421
Heat Input to Gas Turbine (LHV), Btu/h x 10^6	1,675
Steam Injection to Gas Turbine, lb/hr	111,000
Gas Turbine Output, MW	192
Steam Turbine Output, MW	118
Gross Power Output, MW	310
ASU & Gasification Plant Power Consumption, MW	(31.2)
Balance of Plant & Auxiliary Load Power Consumption, MW	(9.5)
Net Power Output, MW	269.3
Plant Heat Rate (HHV), Btu/kW	8,912
Plant Thermal Efficiency (HHV), %	38.3

Table A2

Environmental Emissions Summary* of the Wabash River Greenfield Plant

Total Gas Turbine Emissions	
GT/HRSG Stack Exhaust Flow Rate, lb/hr	3,770,200
GT/HRSG Stack Exhaust Temperature, °F	238
Emissions (at 15% oxygen, dry basis)	
SO_x, ppmvd	3
SO_x as SO_2, lb/hr	23
NO_x, ppmvd	25
NO_x as NO_2, lb/hr	160
CO, ppmvd	15
CO, lbl/hr	55
Incinerator Emissions	
Stack Exhaust Flow Rate, lb/hr	22,120
Stack Exhaust Temperature, °F	500
Emissions (at 3% oxygen, dry basis)	
SO_x, mol% dry	0.666
SO_x as SO_2, lb/hr	290
NO_x, ppmvd	40
NO_x as NO_2, lb/hr	1
CO, ppmvd	50
CO, lbl/hr	1
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	3,792,300
Emissions	
SO_x, ppmvd	42
SO_x as SO_2, lb/hr	312
NO_x, ppmvd	30
NO_x as NO_2, lb/hr	161
CO, ppmvd	17
CO, lbl/hr	56
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	96.8

* Expected emissions performance

A.5 Major Equipment List

Table A3 lists the major pieces of equipment and systems by process area in the Wabash River Greenfield Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit, are not available.

Table A3
Major Equipment List for the Wabash River Greenfield Plant

Area	***Fuel Handling - 100***
100	Unit Train Rail Loop
100	Rotary Coal Car Dumper
100	Rotary Car Dumper Coal Pit
100	Rotary Dumper Vibratory Feeders
100	Rotary Dumper Building & Coal Handling Control Control/Electrical Rooms
100	Rotary Car Dumper Dust Collector
100	Rotary Car Dumper Sump Pumps
100	Coal Car Unloading Conveyor
100	Coal Crusher
100	Reclaim Coal Grizzly
100	Reclaim Conveyor
100	Reclaim Pit Sump Pumps
100	Coal Dust Suppression System
100	Coal Handling Electrical Equipment and Distribution
Area	***Slurry Preparation - 150***
150	Coal Rod Mill (RM)
150	Coal Hopper
150	Recycle Water Storage Tank
150	Slurry Storage Tank
150	Recycle Water Pumps
Area	***ASU - 200***
200	Air Separation Unit Including:
	Air Compressor
	Oxygen Compressor
	Liquid Nitrogen Storage
Area	***ASU & Gasifier Area Cooling Water - 250***
250	Cooling Water Circulating Pump
250	Cooling Tower (S/C)
Area	***Gasification - 300***
300	High Temperature Heat Recovery Unit
300	Slag Crushers
300	Gasifier
300	Barrier Filter
Area	***Slag Handling - 350***
350	Slag Dewatering Bins
350	Gravity Settler
350	Slag Water Tank

Area	***Sulfur Removal - 400***
400	Water Scrubber
400	Acid Gas Removal System
400	Syngas Moisturizer
400	CO_2 Stripper
400	Ammonia Stripper
400	Sour Water Receiver
400	Low Temperature Heat Recovery Unit
400	Amine Reclaim Unit
400	Syngas Heater
400	Recycle Compressor
400	COS Hydrolysis Unit
Area	***Sulfur Recovery - 420***
420	Tail Gas Recycle Compressor
420	Reaction Furnace with Waste Heat Boiler
420	Claus Catalytic Reaction Stages
420	Hydrogenation Reactor
420	Tank Vent Incinerator
420	Sulfur Storage Tank
Area	***GT / HRSG - 500***
500	Gas Turbine Generator (GTG), GE 7FA, Dual Fuel (Oil and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.
500	GTG Erection (S/C)
500	Diesel Oil Storage Tanks (S/C)
500	Diesel Oil Supply Pumps
500	Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, Convective Heat Transfer. With Integral Deaerator
500	HRSG Stack (S/C)
500	HRSG Continuous Emissions Monitoring Equipment
500	HRSG Feedwater Pumps
500	HRSG Blowdown Flash Tank
500	HRSG Atmospheric Flash Tank
500	HRSG Oxygen Scavenger Chemical Injection Skid
500	HRSG pH Control Chemical Injection Skid
500	GTG Iso-phase Bus Duct
500	GTG Synch Breaker
500	Power Block Auxilary Power Transformers
500	Power Block Air Compressors
500	Power Block Compressor Air Receiver
500	Power Block I/A Dryer
500	Power Block Area Sump Pumps
500	Power Block Area DCS System

Area	***STG & Aux. - 600***
600	Steam Turbine Generator (STG) Including: Lube Oil Console, Hydraulic Oil EHC system, Steam Turbine, Generator, Static Exciter, Mark V Control System, Generator Control Panel and Associated Skids.
600	STG Surface Condenser
600	Condenser Hotwell Condensate Pumps
600	Condenser SJAE Skid
600	STG Gland Steam Condenser
600	Power Block - Cooling Tower
600	Power Block Circulating Water Pumps and Motor Drivers
600	Power Block Cooling Water Intake Stationary Screens
600	Power Block Cooling Tower Chlorinator
600	Power Block Cooling Tower Acid Injection Skid
600	STG Synch. Breaker
600	STG Iso-phase Bus Duct
600	STG Step-up Transformer (18 to 230 kV)

Area	***Balance Of Plant - 900***
910	High Voltage Electrical Switch Yard (S/C)
920	Common Onsite Electrical and I/C Distribution
920	DCS
920	In-Plant Communication System
920	15KV, 5KV and 600V Switchgear
920	BOP Electrical Devices
920	Power Transformers
920	Motor Control Centers
930	River Water - Makeup Water Intake and Plant Supply Pipeline
930	Ranney System Intake S/C Including:
	Intake Well
	Pump house
	Makeup Pumps (2 @250 HP)
	Substation & MCC
	Lighting, heating & Ventilation
940	Makeup Water Treatment Storage and Distribution
940	Water Treatment Building Equipment
940	Hydroclone Clarifier
940	Coagulate Storage Silo
940	Clarifier Lime Storage Silo
940	Gravity Filter
940	Clear Well
940	Clear-Well Water Pumps
940	Water Softener Skids
940	Carbon Filters
940	Cation Demineralizer Skids

940	Degasifiers
940	Anion Demineralizer Skids
940	Demineralizer Polishing Bed Skids
940	Bulk Acid Tank
940	Acid Transfer Pumps
940	Demineralizer Acid Day Tank Skid
940	Bulk Caustic Tank Skid
940	Caustic Transfer Pumps
940	Demineralizer Caustic Day Tank Skid
940	Condensate Storage Tanks - S/C
940	Condensate Transfer Pumps
940	Firewater Pump Skids
950	Waste Water Collection and Treatment
950	Oily Waste API Separator
950	Oily Waste Dissolved Air Flotation
950	Oily Waste Storage Tank
950	Sanitary Sewage Treatment Plant
960	Waste Water Outfall
960	Monitoring Equipment
970	Common Mechanical Systems
970	Shop Fabricated Tanks
970	Miscellaneous Horizontal Pumps
970	Auxiliary Boiler
970	Safety Shower System
970	Flare
970	Chemical Storage Equipment
990	Laboratory Equipment

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash Repowering project with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 43 months including two months of performance testing before full commercial operations. Notice to proceed is based on a confirmed Midwest plant site and availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&ID's and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor and air separation unit.

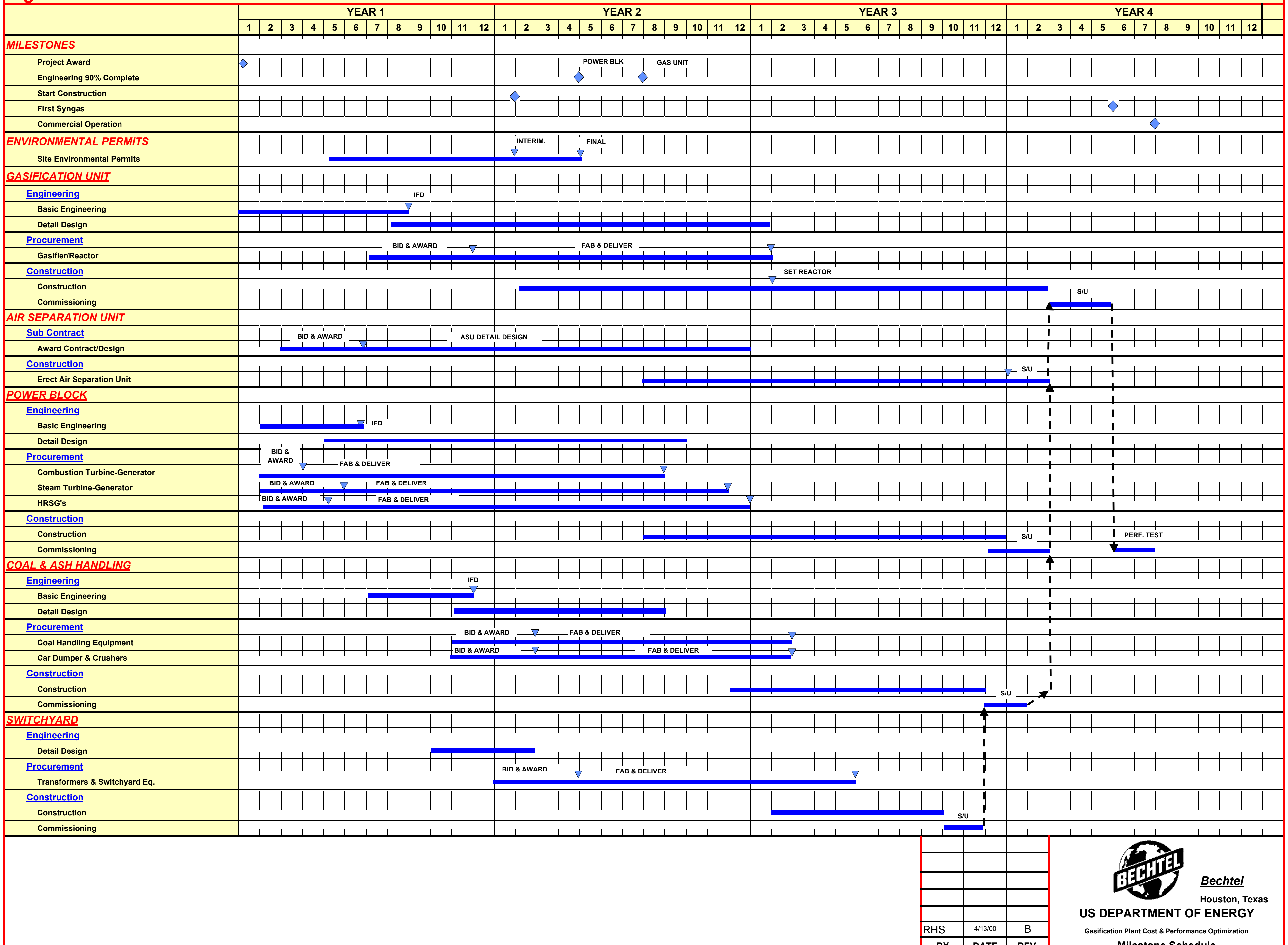
A milestone construction schedule for the major process blocks of the Wabash River Greenfield Plant is shown in Figure A5.

Figure A5

Milestone Construction Schedule

for the Wabash River Greenfield Plant

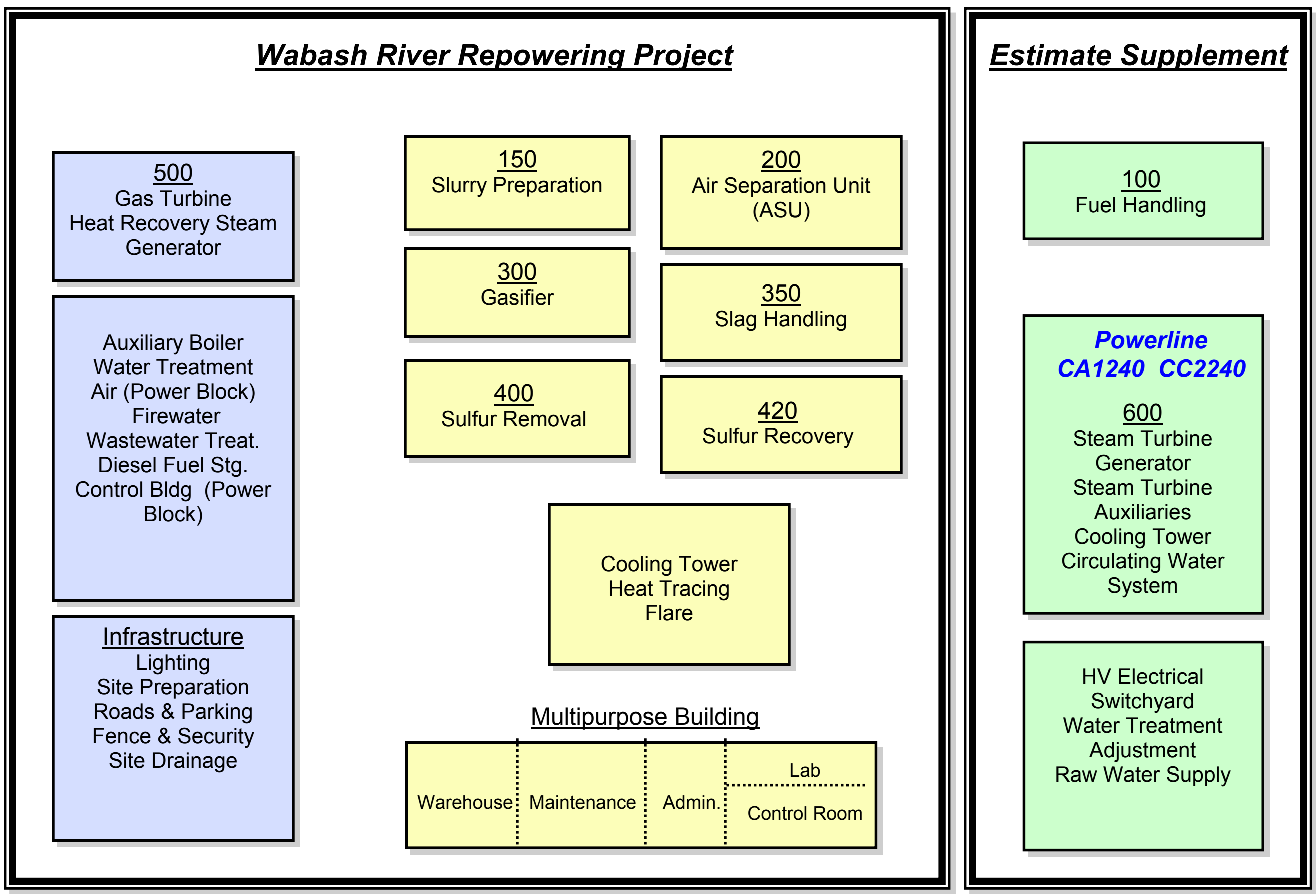
Figure A5 - Milestone Construction Schedule for the Subtask 1.1 Wabash River Greenfield Plant



A.6.2 Capital Cost Summary

A.6.2.1 General

Historical design information, cost data and material quantification was provided from the Wabash River Repowering Project and supplemented where needed to develop the scope for the greenfield plant. The following illustrates the scope breakdown of the source of the information for the Wabash River Greenfield Plant.



Information received from the Wabash River Repowering Project, where possible, was organized by commodities into a work breakdown structure (WBS) to support future task estimates. Some information provided was not easily separable into the desired WBS. These areas were for bulk electrical commodities and support services, normally associated with the Balance of Plant, for the power block. Because of the above, the summary cost includes the traditional balance of plant costs with the process area. The Balance of Plant only includes site preparation, HV switchyard, and the cooling towers.

The complete WBS for Subtask 1.1 follows.

Plant Area	Area	Description
Solids Handling	100	Fuel Handling
Gasification	150	Slurry Preparation
Air Separation Unit	200	Air Separation Unit (ASU)
Gasification	300	Gasifier
Gasification	350	Slag Handling
Gasification	400	Sulfur Removal
Gasification	420	Sulfur Recovery
Power Block	500	Gas Turbine/Heat Recovery Steam Generator (GT/HRSG)
Power Block	600	Steam Turbine Generator (STG) and Auxiliary Equipment
Balance Of Plant	900	Balance Of Plant

Major Equipment

Major equipment was loaded into a data base with physical attributes reflecting size, capacity and power requirements. It also identifies the source of the cost, actual or estimated, for future reference. Equipment for the Greenfield adjustment were either estimated from in-house historic data or from supplier quotes.

Bulk Materials

The Wabash River Repowering Project bulk commodity quantities and pricing for steel, concrete, and piping were used.

Subcontracts

Costs for major subcontracts were provided and represented as a mixture of direct labor and materials. The following major subcontracts were provided from the Wabash River Repowering Project:

- Site work
- Buildings Including Interior Finish, HVAC & Furnishings
- Mechanical Installation
- Painting
- Fire Protection Systems
- Insulation and Electric Heat Tracing
- Start-up Services
- Civil work
- Electrical and Instrumentation Installation
- Cooling Tower (except basin)
- Air Separation Unit
- Elevator
- Gasifier Refractory
- Field Erected Tanks

Construction

Based on the Repowering Project, direct labor costs were provided with subcontract costs. Where appropriate unit rates were adjusted to reflect historic construction productivity to account for the unique and unexpected inefficiencies associated with the Repowering Project.

Home Office Services Costs

The Wabash River Repowering Project home office services were used and supplemented with estimated historic values for the Greenfield adjustment.

Material Take-off

No manual take-offs were done since all commodities were based on the Repowering Project. For piping commodities a COMET model was created for large bore piping in the Gasification area and compared to the actual quantities. The model will be used in future tasks to estimate piping quantities.

6.2.2 Cost Basis

The following established the basis of the cost summary.

- Wabash River costs adjusted from 1994 through the year 2000

  Indices used are based on publicly available sources. Some of resources used are the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index. Major commodities and direct labor rates were individually adjusted based on the indices.
- Site conditions
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence or abandoned mines
  - No layout limitations or restrictions imposed from sources external to the site
- Costs include only areas within the site plan
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)
- The following costs are excluded
  - Contingency and risks
  - Taxes
  - Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
  - Licensing fees

A.6.6.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Wabash River Greenfield Power Plant.

Table A4

Capital Cost Summary of the Wabash River Greenfield Plant

Plant Area	Direct Field Material	Direct Field Labor	Other Costs	Total
Solids Handling	$7,280,000	$6,820,000	$2,820,000	$16,920,000
Air Separation Unit	$26,220,000	$17,480,000	$6,490,000	$50,190,000
Gasification	$145,220,000	$41,950,000	$32,910,000	$220,080,000
Power Block	$93,610,000	$30,800,000	$27,520,000	$151,930,000
Balance Of Plant	$5,480,000	$5,810,000	$2,160,000	$13,450,000
Total	$277,810,000	$102,860,000	$71,900,000	$452,570,000

Notes: (1) Balance of Plant only includes site preparation, HV switchyard and cooling towers (see Section A.6.2.1)

(2) Direct field material is all materials such as equipment and bulks including sub-contracts. Direct field labor is all labor (including indirect field cost) to install direct field materials. Other costs are home office, insurance, construction office and other expenses.

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±5%. The level of accuracy reflects a high degree of confidence based on actual costs for the gasification and air separation areas and estimates for the material handling, power block and balance of plant. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

The estimate is slightly higher than the actual Wabash River Repowering cost of $438MM (non escalated and excludes an estimated $30-40MM savings from use of the existing steam turbine and infrastructure), and it is in agreement with Global Energy's estimate for a greenfield plant. The high confidence level and alignment with expectations provides a good foundation for future subtask estimates.

Appendix B - Subtask 1.2

Petroleum Coke IGCC Coproduction Plant

Introduction

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy (DOE) to promote energy production from fossil fuels in the 21st century. It will integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. It will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 includes plans to give integrated gasification combined cycle (IGCC) systems a major role for the continued use of solid fossil fuels. Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly to build and operate. The goal of this study is to improve the net present value (NPV) of gasification projects by optimizing plant performance, capital cost, and operating costs. The key benefit of doing this methodical cost optimization process off-line is that it removes the schedule constraints associated with project development that tend to inhibit innovation and implementation of new ideas.

In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel Technology & Consulting Company) and Global Energy, Inc. (which recently acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the Destec Gasification Process) a contract to optimize IGCC plant performance.[1] Task 1 of this contract will optimize two IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Task 2 will optimize two different IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of liquid transportation fuels, and (2) coal gasification for electric power with the coproduction of liquid transportation fuels. Task 3 will develop conceptual designs and projected costs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

This appendix describes the results of Subtask 1.2, the non-optimized Petroleum Coke IGCC Coproduction Plant, which will be the basis for development of optimized petroleum coke IGCC coproduction plants in Subtask 1.3.

[1] Contract No. DE-AC26-99FT40342, "Gasification Plant Cost and Performance Optimization"

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[2] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrates a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[3] However, the first year of operation resulted in only a 20% capacity factor, with over one half of the outage time being attributable to the dry char particulate removal system where frequent failures of the ceramic candle filters were experienced. The facility has switched to operation with metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility for the site. Additionally, two successful tests using petroleum coke including one from a refinery processing Mayan crude were completed in November, 1997 and September, 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria. The results of the petroleum coke tests have been previously described.[4]

---

[2] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"
[3] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November, 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.
[4] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.999 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing). The repowering project has demonstrated the ability to run at full load capability (250 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the Project, with a demonstrated heat rate of under 9,000 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-Gas Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

The Wabash River Greenfield Project Plant

The gasification optimization work began with reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that Wabash River project design was transformed into a greenfield IGCC plant design to be used as the basis for developing the designs for the Subtask 1.2 Petroleum Coke IGCC Coproduction Plant and the subsequent optimized coal and coke power and coproduction plant designs.

Since one major focus of this study is the optimization of the gasification plant costs, the following three-stage cost estimating methodology was employed to develop a current year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project, were adjusted for unusual circumstances and escalated to today's values. The costs of any equipment and materials that were not part of the Wabash River project (such as existing facilities), but are required, were added the cost database.

- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Major pieces of equipment that required modifications during the demonstration period were incorporated, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. Bechtel's Multi-Project Acquisition Group (MPAG) worked with manufacturers, fabricators, and suppliers with whom current procurement agreements have been established to provide the most cost-effective pricing. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities to provide a basis for evaluating future changes. This tool enables the study team to make changes in plot plan layout, process improvements, equipment sizes, structural support, etc. and determine the effect on the bulk material requirements.
- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Further evaluation of gasification technologies and other energy related process plants require a standard methodology for estimating the capital costs. The format for this estimating tool based on historical data, escalation indices and vendor quotes was developed and will be employed on subsequent tasks in this study and for future project development activities.

The Petroleum Coke IGCC Coproduction Plant

Since present-day gasification applications are more likely to be based on petroleum coke due to its low fuel value cost, this subtask reconfigured the stand-alone coal-based Wabash River Greenfield Project Plant to use coke and to produce power and hydrogen; i. e., to be a cogeneration plant. Gasifier performance on petroleum coke is based on the successful coke runs at the actual Wabash River project facility. It also relocated the plant to the U. S. Gulf Coast adjacent to a petroleum refinery.

Thus, following the above plant and location adjustments, the plant was enlarged and re-engineered to process petroleum coke, rather than coal, and produce hydrogen and industrial-grade steam in addition to electric power. Because the plant now becomes an integral part of the adjacent petroleum refinery by supplying it with 79 MMscfd of high-purity hydrogen and 980,000 lb/hr of 700 psig/750oF steam, it must be highly reliable since unexpected outages can have severe economic consequences to refinery operations. Because of this reliability requirement, many units and/or portions of units, were spared to maximize plant reliability.

The following Subtask 1.2 (Appendix A) contains a more detailed description, and the design and cost information for the Subtask 1.2 Petroleum Coke IGCC Coproduction Plant.

Appendix B

Subtask 1.2 (Appendix A)

Petroleum Coke IGCC Coproduction Plant

Subtask 1.2 (Appendix A)
Table of Contents

Figures

Subtask 1.2 - Appendix A

Subtask 1.2 – Petroleum Coke IGCC Coproduction Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2500 TPD gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest processing Illinois No. 6 coal.

This appendix summarizes the results of Subtask 1.2. The scope of Subtask 1.2 is to convert the Subtask 1.1 facility into a non-optimized Petroleum Coke IGCC Coproduction Plant producing electric power, hydrogen and steam, and to move the plant to a Gulf Coast location adjacent to a petroleum refinery. It contains the following design and cost information:

- The design basis
- A block flow diagram
- A plant description
- An overall site plan of the IGCC coproduction plant
- An artist's view of the plant site
- An overall material, energy, and utility balance
- A plant performance summary
- An environmental emissions summary
- A major equipment list
- A project schedule
- A capital cost summary

The design information listed above will be the starting point to optimize the design of Subtask 1.3 by using both Global Energy's petroleum coke experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures

The following sections describe the results of Subtask 1.2, the design and cost estimate for the Petroleum Coke IGCC Coproduction Plant.

Section A.2 contains the design basis for the Petroleum Coke IGCC Coproduction Plant. Section A.3 contains descriptions of the various sections of the plant. Section A.4 summarizes the overall plant performance. Section A.5 contains a listing of the major pieces of equipment within the plant. Section A.6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the non-optimized Petroleum Coke IGCC Coproduction Plant.

A.2.1 Capacity

The Petroleum Coke IGCC Coproduction Plant will process a nominal 5,500 TPD of delayed petroleum coke to produce syngas that will fully load two GE 7FA gas turbines at 70° F ambient, 60% relative humidity, and 14.7 psia, and coproduce about 80 MMscfd of hydrogen. It also will export 980,000 lbs/hr of 750 psig / 700°F steam to an adjacent refinery.

A.2.2 Site Conditions

Location	Gulf Coast Refinery
Elevation, Ft	25
Air Temperature	
Maximum, °F	95
Annual Average, °F	70
Minimum, °F	29
Summer Wet Bulb, °F	80
Relative Humidity, %	60
Barometric Pressure, psia	14.7
Seismic Zone	0
Design Wind Speed, MPH	120

A.2.3 Feed

Type	Delayed Petroleum Coke	
	Dry Basis	As Rec'd
HHV, Btu/lb	14,848	14,132
LHV, Btu/lb	14,548	13,846
Analysis, Wt%		
Carbon	88.76	84.48
Hydrogen	3.20	3.05
Nitrogen	0.90	0.86
Sulfur	7.00	6.66
Oxygen	0.00	0.95
Chlorine	50 ppm	47 ppm
V & Ni	1900 ppm	1767 ppm
Ash	0.14	0.13
Moisture	NA	4.83
Total	100	100

A.2.4 Water

Cations	mg/l	As equivalent ppm of CaCO3
Calcium	8.4	21
Copper	0.01	
Iron	2.2	3.9
Magnesium	3.0	12.3
Manganese	< 0.06	
Molybdenum	< 0.01	
Potassium	2.0	2.6
Sodium	19.0	41.4
Zinc	0.01	0.02
Sodium (add to balance)	21.1	46.0
Total Cations		127

Anions	mg/l	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	61.0	50.0
Chloride	16.0	22.6
Sulfide	52.0	54.1
Nitrate - Nitrogen	0.7	0.6
Phosphate	0.6	
Fluoride	no data	
Chloride (add to balance)	0.0	0.0
Total Anions		127

Weak Ions	mg/l	As equivalent ppm of CaCO3
Ammonia Nitrogen	no data	
Total Silica	21.0	

Other Characteristics	mg/l	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	202	
Standard Conductivity	271	
Total Alkalinity		50
Total Hardness		33
Total Organic Carbon	12 to 15	
Turbidity	5 to 25	
PH	6.4 to 7.4	
Total Suspended Solids	10 to 60	

A.3 Plant Description

A.3.1 Block Flow Diagram

The Petroleum Coke IGCC Coproduction Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier/High Temperature Heat Recovery(HTHR)/Dry Char Filtration
    - Sulfur Removal
    - Sulfur Recovery
- Air Separation Unit (ASU)
- Power Block
    - Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG)
    - Steam Turbine Generator(STG)/Auxiliary Equipment
- Hydrogen Production
    - CO Shift
    - Pressure Swing Adsorption (PSA)
    - Hydrogen Compression
- Balance of Plant

Figure A1 is the block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the relative capacity of each train are noted on the BFD.

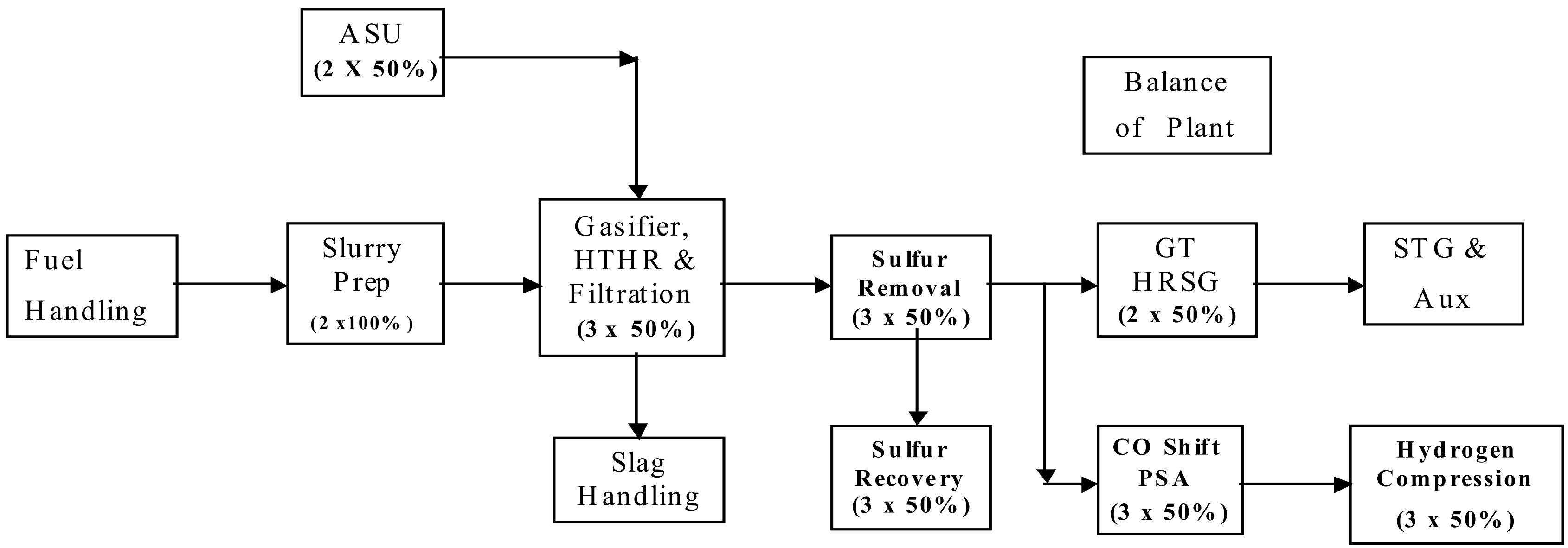
A.3.2 General Description

The plant is divided into the six distinct areas.

- Fuel Handling Unit
- Gasification Plant
- Air Separation Unit
- Power Block
- Hydrogen Plant
- Balance of Plant

Section A.3.3 describes the fuel handling facilities required for transferring petroleum coke from refinery battery limits to on site storage and conveying to the gasification plant.

Figure A1
PETROLEUM COKE IGCC COPRODUCTION PLANT SIMPLIFIED BLOCK FLOW DIAGRAM



Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two stage entrained flow gasifier to convert petroleum coke to syngas. The gasification plant includes several process units to remove impurities in the syngas, similar to the Wabash River repowering plant.

Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95 percent purity oxygen stream is produced as the oxidant for the gasifier. The design is based on the Wabash River plant ASU.

Section A.3.6 describes the power block, which consists of two General Electric 7FA model gas turbines with generators and a steam turbine. The gas turbines use moisturized syngas and steam injection for NOx control and power augmentation.

Section A.3.7 describes the hydrogen plant, which consists of sweet gas CO shift units, Pressure Swing Adsorption (PSA) units, and hydrogen compressors.

Section A.3.8 describes the balance of plant (BOP). The BOP portion of the IGCC coproduction plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Petroleum Coke IGCC Coproduction Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were drawn by the Comet model.

A.3.3 AREA 100 – Fuel Handling

The fuel handling system provides the means to receive, unload, store, and convey the delayed petroleum coke to the storage facility.

Crushed petroleum coke (size 2X0) is transferred from the refinery or barge to the coke storage silos by transfer belt conveyors from the battery limit. Flux is delivered by truck at truck unloading hopper and conveyed to the flux storage silo by flux storage conveyor. Petroleum coke and flux are mixed by the weigh belt feeders and transferred by coke feed conveyors to the day storage bins above the rod mills in the slurry preparation area (area 150).

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur removal. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

The petroleum coke slurry feed for the gasification plant is produced by wet grinding in a pair of 100% capacity rod mills. In order to produce the desired slurry solids concentration, coke is fed to each rod mill with water that is recycled from other areas of the gasification plant. Prepared slurry is stored in agitated tanks.

All tanks, drums, and other areas of potential atmosphere exposure of the product slurry or recycled water are covered and vented into the tank vent collection system for vapor emission control.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery and Particulate Removal

Global Energy's E-GAS™ Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a horizontal refractory lined vessel into which oxygen and preheated coke slurry are atomized via opposing mixer nozzles. The coke and flux slurry, recycle solids, and oxygen are fed in partial combustion quantities at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coke is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide and water. Sulfur in the coke is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are easily removed by downstream processing.

Mineral matter in the coke and flux form a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows up from the horizontal section into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which additional coke slurry is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This additional coke feed serves to lower the temperature of the gas exiting the first stage by the endothermic nature of the equilibrium reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by the addition of syngas from the syngas recycle compressor. No oxygen is introduced into the second stage.

The gas and entrained particulate matter exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

The raw gas leaving the high temperature heat recovery unit passes through a barrier filter unit to remove particulates. The recovered particulates are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir in the top of the bin and goes to a settler in which the remaining slag fines are settled. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, and a water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

The particulate-free gas then passes through a water scrubber to remove water-soluble contaminants from the syngas.

The syngas then is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the desired high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a two train (2x50%) without backup sour water feed storage.

A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam-stripping at a lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiency.

A.3.4.5 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

Two 50% capacity ASUs are provided to deliver the required oxygen for the coke gasification process. Each ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous production.

A.3.6 Power Block

The major components of the power block include two gas turbine generators (GTG), two heat recovery steam generators (HRSG), a steam turbine generator (STG), and numerous supporting facilities.

A.3.6.1 AREA 500 – Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and stack

Each of the two gas turbine generators are General Electric 7FA, nominal 192 MW output each. Each GTG utilizes moisturize syngas and steam injection for $NO_{\times}$ control and power augmentation. Combustion exhaust gases are routed from each GTG to its associated HRSG and stack. Natural gas is used as back-up fuel for the gas turbine startup, shutdown, and short duration transients in syngas supply.

The HRSG receives GT exhaust gases and generates steam at the main steam and reheat steam energy levels. It generates high pressure (HP) steam and provides condensate heating for both the combined cycle and the gasification facilities.

The HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSG boiler includes a steam drum for proper steam purity and to reduce surge during cold start. Large down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

Each stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 – Steam Turbine (ST)

The reheat, condensing turbine includes an integrated HP/IP opposed flow section and an axial flow, single cylinder, LP section. Turbine exhaust steam is condensed in a surface condenser. The reheat design ensures high thermal efficiency and excellent reliability.

A.3.6.3 Power Delivery System

The power delivery system includes the combustion turbine generator output at 18 kilovolts (kV), each is connected through a generator breaker to its associated main power step-up transformer. A separate main step-up transformer and generator breaker is included for the ST generator. The HV switch yard receives the energy from the three generator step-up transformers at 230 kV.

Two auxiliary transformers are connected between the gas turbine generator breakers and the step-up transformers. Due to the large auxiliary load associate with the IGCC coproduction plant, internal power is distributed at 33 kV from the two auxiliary power transformers. The major motor loads in the ASU plants will be serviced by 33/13.8 kV transformers. The balance of the project loads will be served by several substations with 33/4.16 kV transformers supplying double ended electrical bus.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.7 Hydrogen Plant

A.3.7.1 AREA 450 – CO Shift Unit

The clean syngas from the syngas moisturizer and preheater goes to the CO shift reactors where approximately 97 to 98 percent of the carbon monoxide is converted to hydrogen. To accommodate the required capacity and reliability, three 50% trains of a two temperature stage system (i.e., a high temperature stage followed by a low temperature stage) are needed as limited by maximum reactor vessel diameter.

Hot gas from the first high temperature shift reactor preheats the syngas before it enters the ZnO reactor to remove trace amounts of sulfur components in the syngas. About half of the syngas from the ZnO reactor flows to the first high temperature (HT) reactor, and the other half to the second HT reactor.

The shift reaction is highly exothermic. High temperatures favor fast reaction rates but result in unfavorable equilibrium conditions. Also, the maximum allowable outlet temperature must be below the catalyst sintering point and within the limits for practical vessel design. Low temperatures favor the equilibrium conditions that allow the shift reaction to go to completion which results in low CO levels in the product gas.

The two initial high temperature shift reactors are designed to achieve high reaction rates at highest allowable outlet temperature. Medium pressure steam is added to the first HT reactor after it is preheated by the hot syngas gas from the first HT reactor. The hot shifted gas from the first HT reactor is combined with the unshifted syngas from the ZnO reactor and flows to the second HT reactor.

The hot syngas gas from the second HT reactor is cooled by two steam generators producing medium pressure (420 psig) and low pressure (50 psig) steam, and the enters the low temperature shift reactor. In the low temperature (LT) shift reactor, the temperatures are kept low to obtain a low CO level in the product gas. However, the inlet temperature to the reactor must be kept above the water dew point to avoid the catalyst being deactivated by the presence of liquid water.

The shifted gas from the LT reactor is first cooled in a steam generator producing 50 psig steam. The shifted gas is further cooled by an air cooler and a trim cooler using cooling water before going to the Pressure Swing Adsorption unit. Process condensate is separated in the knock-out drum and sent to condensate treatment.

A.3.7.2 AREA 460 - Pressure Swing Adsorption Unit (PSA)

The shifted gas from the CO shift unit is sent to the pressure swing adsorbers for purification of the hydrogen product. Hydrogen recovery is 85%. The PSA system is based on the principle of pressure reduction and rapid cycle operation to remove impurities from the adsorbent. It consists of three major parts, i.e., adsorber vessels filled with adsorbent, a prefabricated valve skid, and a control panel containing the cycle control system.

A complete PSA cycle consists of four basic steps: adsorption, depressurization, purge at low pressure, and repressurization. Multiple adsorbent beds are used for high throughputs and hydrogen recovery.

Approximately 79 MMscfd of 99% hydrogen is produced and sent to the hydrogen compressors. The tail gas from the PSA is sent to the refinery as low BTU fuel gas at 5 psig without further compression.

A.3.7.3 AREA 470 – Hydrogen Compression

The hydrogen from the PSA unit is compressed to 1000 psig by the hydrogen compressors and delivered to the adjacent petroleum refinery.

A.3.8 AREA 900 – Balance of Plant

A.3.8.1 Cooling Water System

The design includes two cooling water systems. One provides the cooling duty for the power block. A separate system provides the cooling duty for the air separation unit and equipment cooling throughout the gasification facility.

The major components of the cooling water system consist of a cooling tower and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. Both cooling towers are multi-cell mechanical draft towers, sized to provide the maximum required heat rejection for any startup or transient condition at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.8.2 Fresh Water Supply

River water from an industrial water supply network is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.8.3 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, the hydrogen plant, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.8.4 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the refinery waste water system.

A.3.8.5 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The service air system consists of air compressors, air receivers, hose stations, and piping distribution for each unit.

The instrument air system consists of air receivers, air dryers, and a piping distribution system.

A.3.8.6 Incineration System

The tank vent stream is composed of primarily air purged through various in-process storage tanks and may contain very small amounts of acid gas. During process upsets of SRU, tail gas streams can be combined with the tank vent system before treatment in a high temperature incinerator. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.8.7 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.8.8 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC power plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated in the combined cycle mode from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or both; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, and the coke handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical GT, ST, and generator, and ASU control parameters.

This approach retains control of IGCP equipment used to transport the coke, control turbines and generators, and to support the ASU. Other balance of plant equipment such as air compressors, condenser vacuum pumps, and water treatment use either local PLCs, or contact and relay control cabinets to operate the respective equipment. All remaining plant components are exclusively controlled by the DCS including the HRSG, the gasifier, tail gas treatment, hydrogen plant, electrical distribution, and other power block and gasification support systems.

A.3.8.9 Buildings

The plant has a central building housing the main control room, office, training, other administration areas and a warehouse/maintenance area. Other buildings are provided for water treatment equipment and MCCs. The buildings, with the exception of water treatment, are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment.

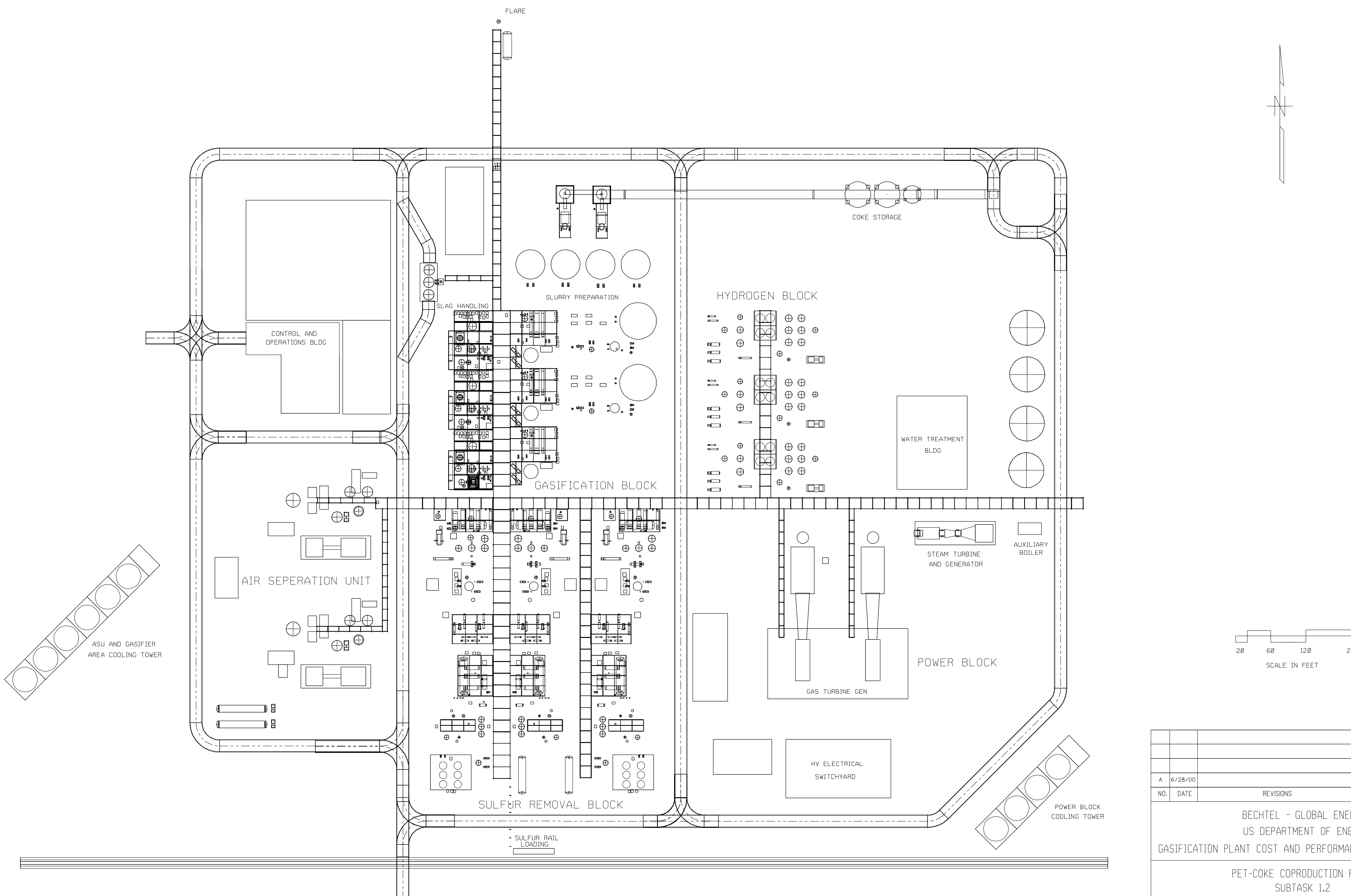
A.3.8.10 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the

Petroleum Coke IGCC Coproduction Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A	6/28/00						

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

PET-COKE COPRODUCTION PLANT
SUBTASK 1.2

JOB No: 24355-104

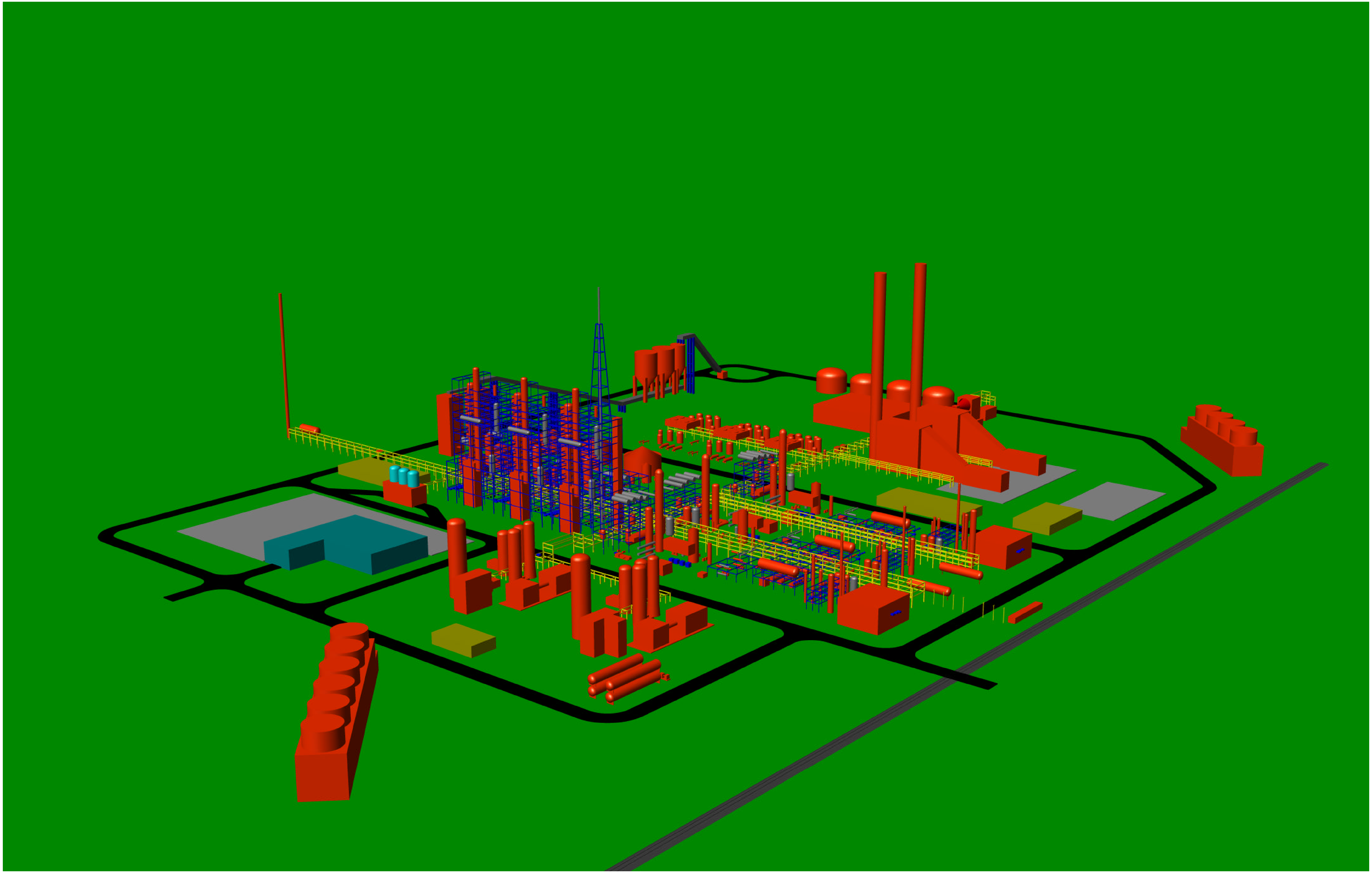
GASIFICATION PLANT
SITE PLAN

SCALE: SK - 00002 REV. A

Figure A3

Artist's Conception of the

Petroleum Coke IGCC Coproduction Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, the Petroleum Coke IGCC Coproduction Plant Detailed Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 5,249 t/d of dry petroleum coke and produces 395 MWe of export electric power, 367 t/d of sulfur, 190 t/d of slag (containing 15 wt% water), and exports to the adjacent petroleum refinery 79 MMscfd of hydrogen and 980,000 lbs/hr of 700 psig/ 750°F steam. It also consumes107 t/d of flux, 686,000 lbs/hr of condensate return from the refinery, and 54,830 gpm of river water.

D.4.2 Performance Summary

Plant performance is based on the petroleum coke IGCC coproduction plant configuration including a GE 7FA gas turbine. Global Energy provided a heat and material balance for these facilities, using the design basis petroleum coke. This information was then integrated with a HRSG and reheat steam turbine. The GT Pro computer simulation program was used to simulate combined cycle performance and plant integration.

Table A1 summarizes the overall performance of the Petroleum Coke IGCC Coproduction Plant. As shown in the table, the oxygen input to the gasifiers is 5,962 t/d, and the heat input is 6,495 MMBtu/hr. The two gas turbines have a cold gas efficiency of 76.9% and produce 384 MW of power from their generators. The steam turbine produces another 118.8 MW of power for a total power generation of 502.8 MW. Internal power usage consumes 108.5 MW leaving a net power production of 395.8 MW for export.

Table A2 summarizes the expected emissions from the Petroleum Coke IGCC Coproduction Plant. The GE 7FA gas turbines and HRSG system has a stack exhaust flow rate of 7,577,700 lb/hr at 243°F. On a dry basis adjusted to 15% oxygen, these gases have a SOx concentration of 3 ppmv, a NOx concentration of 25 ppmv, and a CO concentraion of 15 ppmv. The incinerator stack has an exhaust flow rate of 10,960 lb/hr at 500°F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 1.09 mol%, a NOx concentration of 40 ppmv, and a CO concentraion of 50 ppmv.

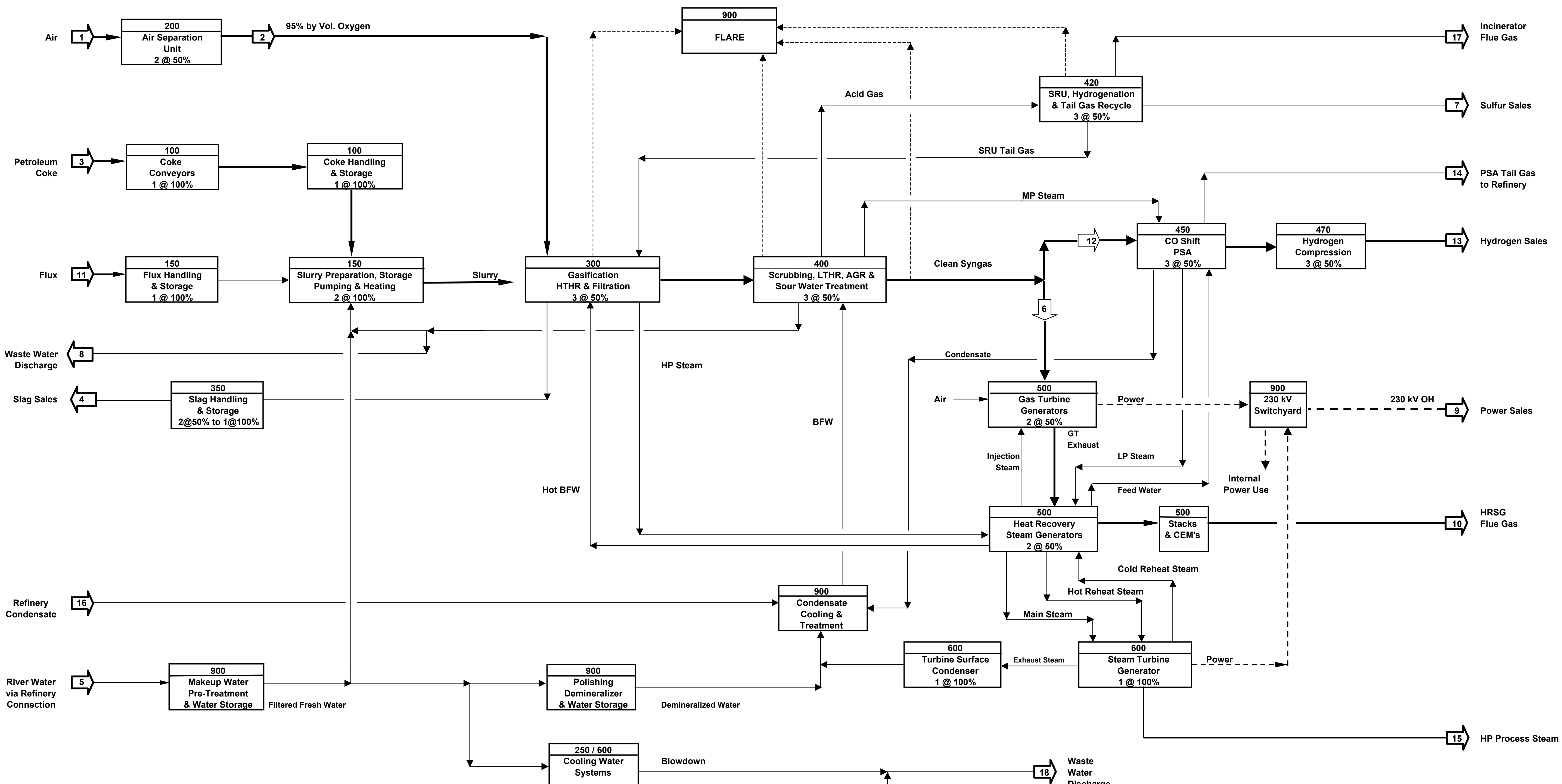
The plant emits 7,588,700 lbs/hr of total exhaust gases having an average SOx concentration of 20 ppmv, an average NOx concentration of 30 ppmv, and an average CO concentraion of 17 ppmv. Expressed another way, this is 306 lb/hr of SOx (as SO_2), 325 lb/hr of NOx (as NO_2), and 111 lb/hr of CO.

The sulfur removal is 99.4%.

Figure A4

Detailed Block Flow Diagram of the

Petroleum Coke IGCC Coproduction Plant



NOTE: Capacity Percentages are based on total plant capacity.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 27,129 Tons/Day	Oxygen 5,962 Tons/Day	Coke 5,249 Tons/Day	Slag 190 Tons/Day	Water 2,415,000 Lb/Hr	Syngas 861,915 Lb/Hr	Sulfur 367 Tons/Day	Water 28,340 Lb/Hr	Power 395,800 kWe	Flue Gas 7,572,000 Lb/Hr	Flux 107 Tons/Day	Syngas 342,960 Lb/Hr	Hydrogen 79 MMSCFD	Tail Gas 100 MMSCFD	HP Steam 980,000 Lb/Hr	Condensate 686,000 Lb/Hr	Flue Gas 10,956 Lb/Hr	Waste 479,000 Lb/Hr			
Nominal Pressure - psig	Atmos.	540	NA	NA	50	320	NA	62	NA	Atmos.	NA	320	1000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	NA	NA	70	530	NA	105	NA	243	NA	530	120	110	750	190	500	71			
HHV Btu/lb	NA	NA	14,848	NA	NA	4,123	NA	NA	NA	NA	NA	4,123	NA	909	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	14,548	NA	NA	3,914	NA	NA	NA	NA	NA	3,914	NA	801	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,495	NA	NA	3,553	NA	NA	NA	NA	NA	1,414	NA	363	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	6,364	NA	NA	3,374	NA	NA	NA	NA	NA	1,342	NA	320	NA	NA	NA	NA			
Notes	Dry Basis	95% O2	Dry Basis	15%Wtr.	4,830 GPM	to GT	Sales	57 GPM	230 kV			for H2	Sales	Sales	Sales	Return		958 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.2

PETROLEUM COKE IGCC COPRODUCTION PLANT

BLOCK FLOW DIAGRAM

Revision 2

File:Fig A4 1.2.xls

February 21, 2002

Table A1

Performance Summary of the Petroleum Coke IGCC Coproduction Plant

Ambient Temperature, °F	70
Coke Feed, as received, TPD	5,515
Dry Coke Feed to Gasifiers, TPD	5,249
Total Fresh Water Consumption, gpm	4,800
Condensate Returned from the Refinery, gpm	1,372
Flux, TPD	107
Sulfur, TPD	367
Slag Produced, TPD (15% moisture)	190
HP Steam Export, lb/hr	980,000
Hydrogen Production, MMscfd	79.4
Fuel Gas Export, MMscfd	99.6
MMBtu/hr (HHV)	363
Total Oxygen Feed to the Gasifiers, TPD	5,962
Heat Input to the Gasifiers (HHV), Btu/hr x 10^6	6,495
Cold Gas Efficiency at the Gas Turbine (HHV), %	76.9
Fuel Input to Gas Turbines, lb/hr	861,915
Heat Input to Gas Turbines (LHV), Btu/hr x 10^6	3,374
Steam Injection to Gas Turbines, lb/hr	164,205
Gas Turbines Output, MW	384
Steam Turbine Output, MW	118.8
Gross Power Output, MW	502.8
ASU & Gasification Plant Power Consumption, MW	(84)
Balance of Plant & Auxiliary Load Power Consumption, MW	(15.2)
Hydrogen Plant & Compressors, MW	(7.8)
Net Power Output, MW	395.8

Table A2

Environmental Emissions Summary* of the Petroleum Coke IGCC Coproduction Plant

Total Gas Turbine Emissions	
GT/HRSG Stack Exhaust Flow Rate, lb/hr	7,577,700
GT/HRSG Stack Exhaust Temperature, °F	243
Emissions (at 15% oxygen, dry basis)	
SO_x, ppmvd	3
SO_x as SO_2, lb/hr	46
NO_x, ppmvd	25
NO_x as NO_2, lb/hr	325
CO, ppmvd	15
CO, lbl/hr	110
Incinerator Emissions	
Stack Exhaust Flow Rate, lb/hr	10,960+
Stack Exhaust Temperature, °F	500
Emissions (at 3% oxygen, dry basis)	
SO_x, mol% dry	1.09
SO_x as SO_2, lb/hr	260
NO_x, ppmvd	40
NO_x as NO_2, lb/hr	0.3
CO, ppmvd	50
CO, lbl/hr	0.5
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	7,588,700+
Emissions	
SO_x, ppmvd	20
SO_x as SO_2, lb/hr	306
NO_x, ppmvd	30
NO_x as NO_2, lb/hr	325
CO, ppmvd	17
CO, lbl/hr	111
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	99.5

* Expected emissions performance
+ Excludes PSA tail gas which is sold the refinery as low Btu fuel gas

D.5 Major Equipment List

Table A3 lists the major pieces of equipment and systems by process area in the Petroleum Coke IGCC Coproduction Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit and the PSA unit, are not available.

Table A3
Major Equipment of the Petroleum Coke IGCC Coproduction Plant

Area	***Fuel Handling - 100***
100	Belt Conveyor
100	Coke Storage Silo
100	Truck Unloading Hopper
100	Flux Belt Feeder
100	Flux Storage Silo
100	Weigh Belt Feeder
100	Magnetic Separator
100	Day Storage Bin
100	Dust Collector
Area	***Slurry Preparation - 150***
150	Rod Mill (RM)
150	Coke Hopper
150	Recycle Water Storage Tank
150	Slurry Storage Tank
150	Recycle Water Pumps
Area	***ASU - 200***
200	Air Separation Unit Including:
	Air Compressor
	Oxygen Compressor
	Liquid Nitrogen Storage
Area	***ASU & Gasifier Area Cooling Water - 250***
250	Cooling Water Circulation Pump
250	Cooling Tower (S/C)
Area	***Gasification - 300***
300	High Temperature Heat Recovery Unit
300	Slag Crushers
300	Gasifier
300	Barrier Filter
Area	***Slag Handling - 350***
350	Slag Dewatering Bins
350	Gravity Settler
350	Slag Water Tank

Area	Sulfur Removal - 400
400	Water Scrubber
400	Acid Gas Removal System
400	Syngas Moisturizer
400	CO_2 Stripper
400	Ammonia Stripper
400	Sour Water Receiver
400	Low Temperature Heat Recovery Unit
400	Amine Reclaim Unit
400	Syngas Heater
400	Recycle Compressor
400	COS Hydrolysis Unit
Area	**Sulfur Recovery - 420**
420	Tail Gas Recycle Compressor
420	Reaction Furnace with Waste Heat Boiler
420	Claus Catalytic Reaction Stages
420	Hydrogenation Reactor
420	Tank Vent Incinerator
420	Sulfur Storage Tank
Area	**CO Shift - 450**
450	ZnO Reactor
450	HT Shift Reactor
450	LT Shift Reactor
450	Gas-gas Exchanger
450	Steam Generator
450	Air Cooler
450	Start-up Fired Heater
Area	**PSA- 460**
460	PSA Unit
Area	**Hydrogen Compression - 470**
470	Hydrogen Compressor
Area	**GT / HRSG - 500**
500	Gas Turbine Generator (GTG), GE 7FA, Dual Fuel (Nat Gas and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.
500	GTG Erection (S/C)
500	Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, Convective Heat Transfer. With Integral Deaerator
500	HRSG Stack (S/C)
500	HRSG Continuous Emissions Monitoring Equipment
500	HRSG Feedwater Pumps
500	HRSG Blowdown Flash Tank
500	HRSG Atmospheric Flash Tank
500	HRSG Oxygen Scavenger Chemical Injection Skid
500	HRSG pH Control Chemical Injection Skid

500	GTG Iso-phase Bus Duct
500	GTG Synch Breaker
500	Power Block Auxiliary Power Transformers
500	Power Block Air Compressors
500	Power Block Compressed Air Receiver
500	Power Block I/A Dryer
500	Power Block Area Sump Pumps
500	Power Block Area DCS System
Area	***STG & Aux. - 600***
600	Steam Turbine Generator (STG) - Including: Lube Oil Console, Hydraulic Oil EHC system, Steam Turbine, Generator, Static Exciter, Mark V Control System, Generator Control Panel and Associated Skids.
600	STG Surface Condenser
600	Condenser Hotwell Condensate Pumps
600	Condenser SJAE Skid
600	STG Gland Steam Condenser
600	Power Block - Cooling Tower
600	Power Block Circulating Water Pumps and Motor Drivers
600	Power Block Cooling Water Intake Stationary Screens
600	Power Block Cooling Tower Chlorinator
600	Power Block Cooling Tower Acid Injection Skid
600	STG Synch. Breaker
600	STG Iso-phase Bus Duct
600	STG Step-up Transformer (18 to 230 kV)

Area	***Balance Of Plant - 900***
910	High Voltage Electrical Switch Yard (S/C)
920	Common Onsite Electrical and I/C Distribution
920	DCS
920	In-Plant Communication System
920	15KV, 5KV and 600V Switchgear
920	BOP Electrical Devices
920	Power Transformers
920	Motor Control Centers
940	Makeup Water Treatment Storage and Distribution
940	Water Treatment Building Equipment
940	Carbon Filters
940	Cation Demineralizer Skids
940	Degasifiers
940	Anion Demineralizer. Skids
940	Demineralizer Polishing Bed Skids
940	Bulk Acid Tank
940	Acid Transfer Pumps
940	Demineralizer Acid Day Tank Skid
940	Bulk Caustic Tank Skid
940	Caustic Transfer Pumps

940	Demineralizer Caustic Day Tank Skid
940	Condensate Storage Tanks - S/C
940	Condensate Transfer Pumps
940	Firewater Pump Skids
950	Waste Water Collection and Treatment
950	Oily Waste API Separator
950	Oily Waste Dissolved Air Flotation
950	Oily Waste Storage Tank
950	Sanitary Sewage Treatment Plant
960	Waste Water Outfall
960	Monitoring Equipment
970	Common Mechanical Systems
970	Shop Fabricated Tanks
970	Miscellaneous Horizontal Pumps
970	Auxiliary Boiler
970	Safety Shower System
970	Flare
970	Chemical Storage Equipment
990	Laboratory Equipment

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.2 scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 52 months which included two months for testing before full commercial operation. Notice to proceed is based on a confirmed Gulf Coast plant site and availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor and air separation unit.

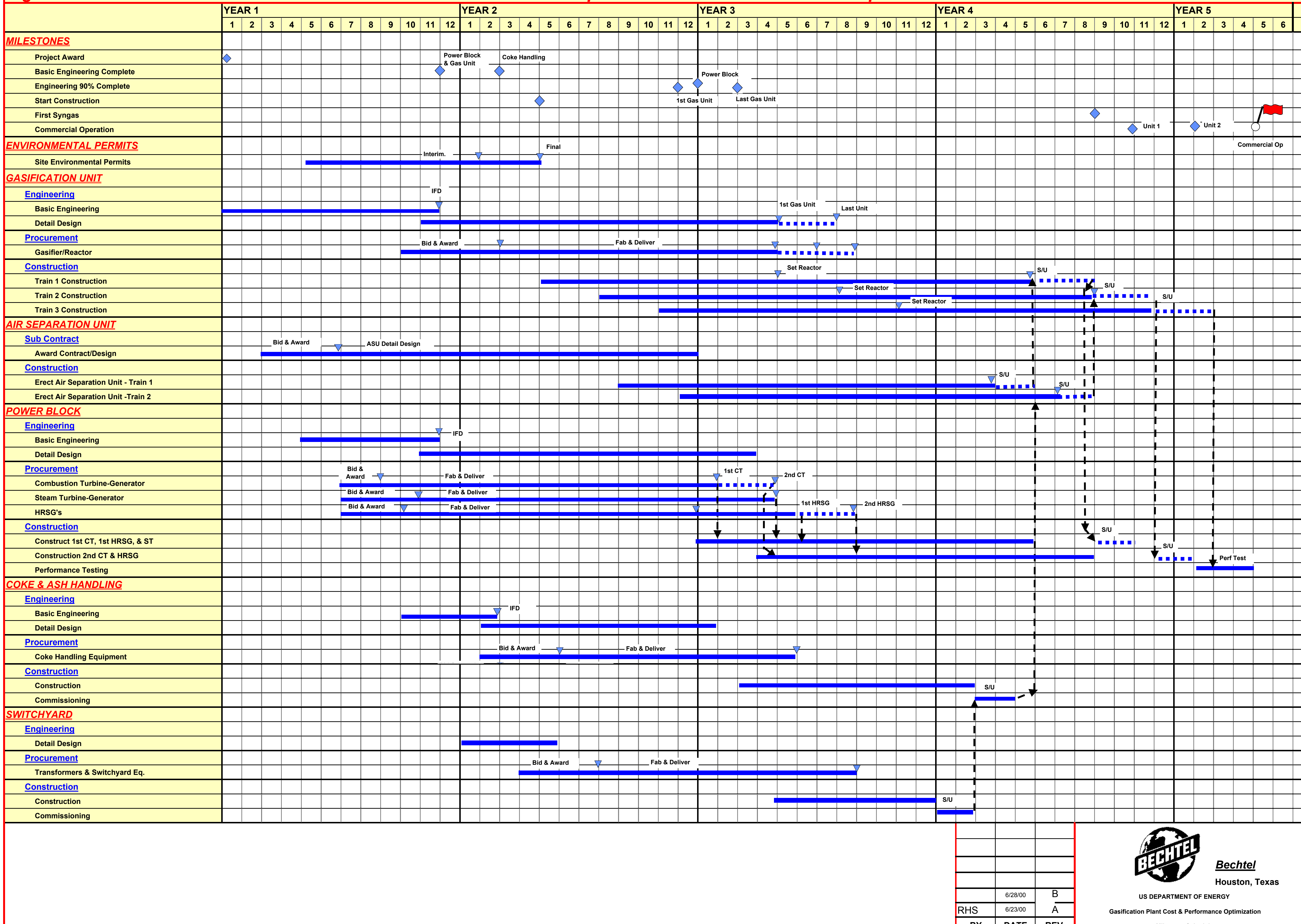
The milestone construction schedule for the major process blocks of the Petroleum Coke IGCC Coproduction Plant is shown in Figure A5.

Figure A5

Milestone Construction Schedule for the

Petroleum Coke IGCC Coproduction Plant

Figure A5 - Milestone Construction Schedule for the Subtask 1.2 Non-optimized Petroleum Coke IGCC Coproduction Plant

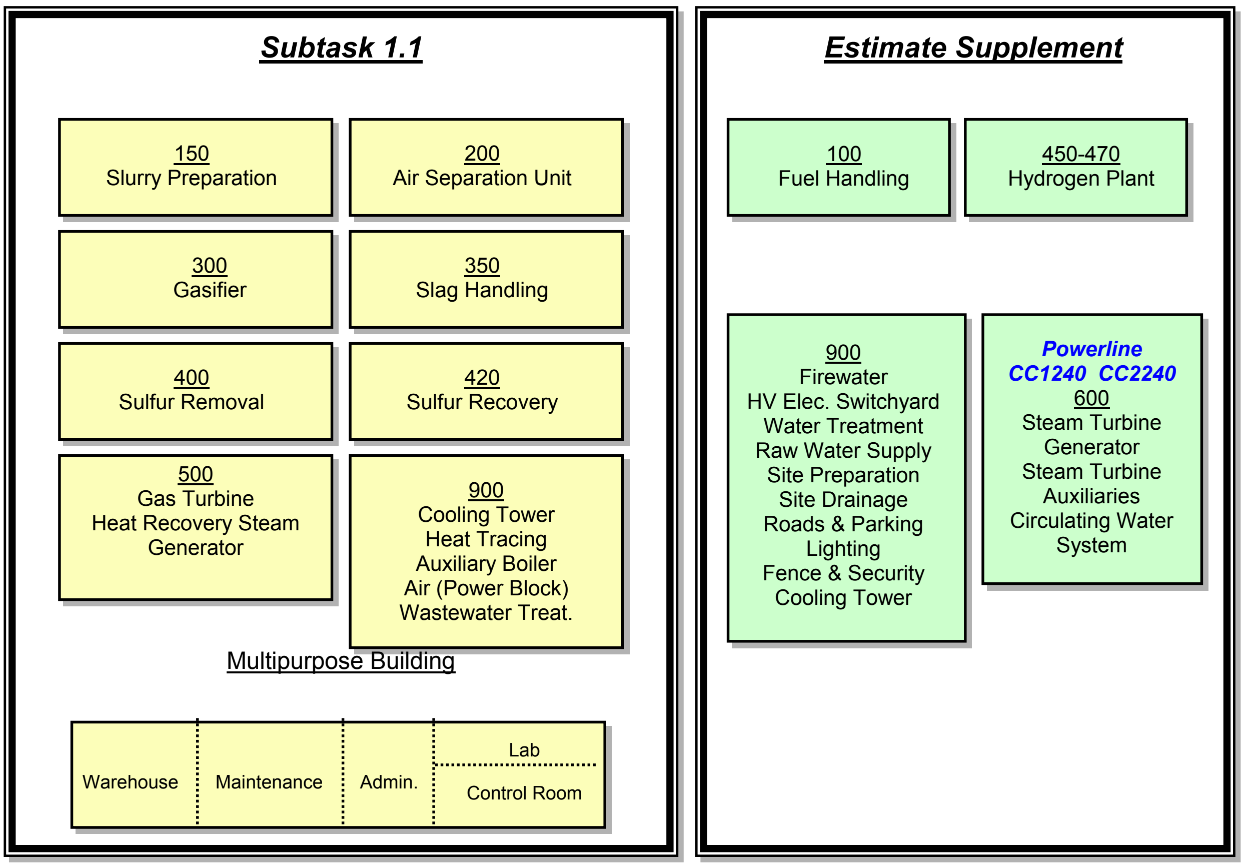


A.6.2 Capital Cost Summary

A.6.2.1 General

The estimate developed for Subtask 1.1 was used where possible as the basis for this estimate. Both cost data and material quantifications are used and supplemented, as needed, to reflect the Petroleum Coke IGCC Coproduction Plant scope for the Gulf Coast location.

The following illustrates the scope breakdown of the source of the information.



Information from Subtask 1.2 is organized by commodities into a work breakdown structure (WBS) similar to that of Subtask 1.1. The complete WBS for Subtask 1.2 follows.

Plant Area	Area	Description
Solids Handling	100	Fuel Handling
Gasification	150	Slurry Preparation
Air Separation Unit	200	Air Separation Unit (ASU)
Gasification	300	Gasifier

Plant Area	Area	Description
Gasification	350	Slag Handling
Gasification	400	Sulfur Removal
Gasification	420	Sulfur Recovery
Hydrogen Production	450-470	CO Shift, PSA, H2 Compression
Power Block	500	Gas Turbine/Heat Recovery Steam Generator (GT/HRSG)
Power Block	600	Steam Turbine Generator (STG) and Auxiliary
Balance Of Plant	900	Balance Of Plant

Note: The multipurpose building and DCS are included in the Gasification area.

Major Equipment

Major equipment from Subtask 1.1 was loaded into a data base and modified to reflect the scope of Subtask 1.2. Modifications include changes in equipment duty, quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

Bulk Materials

Wabash River Repowering Project bulk commodity pricing for steel, concrete, and piping are used, and the quantities were adjusted to reflect the scope and site plan for this subtask.

Subcontracts

Where possible the costs for the major subcontracts from Subtask 1.1 are used as the basis. The costs represent a mixture of direct labor and materials. The following is a list of the major subcontracts:

- Buildings including Interior Finish, HVAC, & Furnishings
- Air Separation Unit
- Elevator
- Gasifier Refractory
- Start-up Services
- Insulation and Electric Heat Tracing
- Cooling Tower (except basin)
- Painting
- Field Erected Tanks

Construction

Labor rates are based on Gulf Coast merit shop rates and historic productivity factors. Union labor is used for refractory installation.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.2. Power block costs are based on historic values.

Material Take-off

Subtask 1.1 quantities were used as the basis and adjusted to reflect the scope and site plan for this task. Concrete, steel and instrumentation were adjusted on an area by area basis reflecting the increased numbers of process trains. The basis for piping adjustment was developed from quantities generated by the COMET model. Electrical quantities were manually adjusted for this subtask.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000
  Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- Site Conditions
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Tie-ins to the adjoining refinery are located on the north and east sides of the site
  - Coke is provided at the battery limits on the north side of the site
- Cost includes only areas within the site plan
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)
- The following costs are excluded
  - Contingency and risks
  - Taxes
  - Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
  - Licensing fees

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Petroleum Coke IGCC Coproduction Plant.

Table A4

Capital Cost Summary of the Petroleum Coke IGCC Coproduction Plant

Plant Area				
Solids Handling	6,900,000	4,500,000	1,549,000	12,949,000
Air Separation Unit	66,788,000	41,829,000	12,571,000	121,187,000
Gasification	322,316,000	133,976,000	84,664,000	540,956,000
Hydrogen Production	44,180,000	6,193,000	10,608,000	60,981,000
Power Block	144,391,000	39,994,000	41,986,000	226,371,000
Balance Of Plant	18,112,000	8,970,000	3,674,000	30,756,000
Total	602,686,000	235,462,000	155,052,000	993,200,000

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ± 11%. The level of accuracy reflects a high degree of confidence based on actual costs for the gasification and air separation areas as a basis for adjusting for the Subtask 1.2 scope. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

Appendix C - Subtask 1.3

Optimized Petroleum Coke IGCC Coproduction Plant

Appendix C (Subtask 1.3)

Executive Summary

Global Energy's Wabash River Coal Gasification Repowering Program IGCC plant is one of the cleanest and most efficient coal fueled power plants in the United States. This plant currently operates on both coal and delayed petroleum coke. Bechtel and Global Energy (under Department of Energy sponsorship) used the Wabash River plant as a starting design and cost estimate basis to design an optimized petroleum coke IGCC coproduction plant. The optimized petroleum coke IGCC coproduction plant consumes 5,400 TPD of dry petroleum coke and produces 461 MW of electric power, 372 TPD of sulfur, and 80 MMscfd of hydrogen and 980,000 lb/hr of 700 psig / 750^{o}F steam for an adjacent petroleum refinery.

The optimized plant design was developed in three steps. In the first step, a greenfield plant processing Illinois No. 6 coal was developed to provide current cost information for a plant configuration that is equivalent to the Wabash River Coal Gasification Repowering Program facility. This step produced a design and current cost information for the entire plant including the existing items (or their equivalent) that were reused during the repowering project. The second step generated a non-optimized plant configuration for a petroleum coke IGCC coproduction plant located on the U. S. Gulf Coast. This plant based on current Wabash technology produces about double the amount of power as well as hydrogen and steam for sale to an adjacent petroleum refinery.

In the final step, the configuration was optimized using value engineering and employing several process design changes with state-of-the-art equipment and technology to increase efficiency and reduce construction and operating costs. The net result of these improvements is a simpler, more efficient, less polluting IGCC coproduction (base case) plant that costs about 764 MM$, 23% less than the non-optimized plant. Part of the savings is a result of a reduction in the number of complete parallel gasification and hydrogen production trains from three to two. A preferred plant design containing only a spare gasification train will cost about 813 MM$, an 18% cost reduction compared to the non-optimized plant. On the same complete three-train plant basis as the non-optimized plant, the cost reduction would be about 11%. In all optimized cases, the savings essentially are in the gasification and balance of plant areas, and the savings range from 18 to 34%.

Based on a current day economic scenario with the product prices indexed to a $3.00 MMBtu natural gas price, the preferred plant design is expected to have a return on investment of about 18%, and the base case design is expected to have a return on investment of 16%. These returns are 7 to 9% better than the non-optimized plant which would have a return on investment of just under 9%.

Additionally, based on Wabash River operating experience over the last two years with the dry char particulate filters and additional analysis of a cyclone plus dry filter system, Global

Energy is confident that the cost of a dry particulate removal system can be significantly reduced. The new system would include a cyclone similar to that in the hybrid wet system, but the wet scrubber in each gasification train would be replaced by a single redesigned dry char filter. Recent operating experience on petroleum coke projects this dry filter system will have near 100% availability, resulting in increased plant availability with only one annual scheduled outage. Employing this dry system will increase the plant availability by 0.5%, increase the power output by 8.5 MW, reduce the plant cost by 8 to 12 MM$, and reduce the O&M cost. Therefore, replacing the hybrid wet/dry particulate removal system with an advanced cyclone /dry filter system should increase the ROI by 1.5% for the above cases, thereby making dry char filtration the preferred particulate removal system for the next plant.

Appendix C (Subtask 1.3)
Table of Contents

Figures

Appendix A – Optimized Petroleum Coke IGCC Coproduction Plant

<u>Tables</u>

<u>Figures</u>

Appendix B – Spare Solids Processing Petroleum Coke IGCC Coproduction Plant

Appendix C – Financial Model Analysis Input

Preface

Current market opportunities for IGCC (based on recent proposal requests) are large multi-train, multi-product petroleum coke IGCC co-production plants and large mine-mouth coal IGCC plants. This appendix (subtask report) describes several possible plant configurations for a coke IGCC coproduction plant starting from the non-optimized Subtask 1.2 design. It also discusses the availability and cost analysis that were done to select an optimized case. However the optimized case may change depending on the project specific requirements; therefore, these alternate configurations will allow a potential owner to revisit the selection analysis.

The size of the coke IGCC coproduction plant was set by hydrogen production, steam demand, and reliability requirements for both products. Hydrogen capacity was set based on the size of a typical steam methane reforming (SMR) system (~80 MMscfd), and the hydrogen reliability was set at >98% to match SMR operations and refinery needs. It was assumed that at least one spare gasification train is required for continuous hydrogen production and/or for power production. Furthermore the design should allow turn down and/or operation with some natural gas, if necessary, and include a spare power train to improve the project economics and to minimize the refinery's use of the power grid for backup. This can be done with three gasifiers that are slightly larger than those at Wabash River or by two gasification trains that are 50% larger than the Wabash River gasifiers. The larger option was selected because Global Energy was confident the gasifier capacity could be increased by 50%, and the Wabash River reactors are oversized for petroleum coke, especially with the efficiency improvement from full slurry quench (FSQ). This approach also maximizes the economy of scale benefit to the hydrogen production. This also appears to result in high availability and a hydrogen price that is competitive with hydrogen from natural gas by SMR. Application of the Value Improving Practices methodology further optimized the system.

The key to any study or project development activity is the establishment of a comprehensive design basis; including feedstock properties, required product slate and specifications; required classes of plant quality (CPQ, environmental criteria, meteorological data; site information, gas turbine performance, an availability target, and a sparing philosophy

Global Energy's experience at Wabash River, Bechtel's design know how, and this study can be used to develop optimized designs for IGCC coproduction plants in various market scenarios and considering various financial drivers. Some of the cases discussed here apply directly. Others may need to be discussed with members of the study team to determine the impact of project specific requirements

Section 1
Introduction

The objective of this Gasification Plant Cost and Performance Optimization Project is to develop optimized engineering designs and costs for several Integrated Gasification Combined Cycle (IGCC) plant configurations. These optimized IGCC plant systems build on the commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project.[1] The Wabash River Repowering Project consists of a nominal 2,500 TPD E-GAS™ gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

Task 1 of this IGCC Plant Cost and Performance Optimization study consists of the following nine subtasks:

- Subtask 1.1 – Expand the Wabash River Project facility design to a greenfield unit
- Subtask 1.2 – Coke based IGCC plant with the coproduction of steam and hydrogen
- Subtask 1.3 – Optimized coke based IGCC plant with the coproduction of steam and hydrogen
- Subtask 1.4 – Optimized coal to power IGCC plant
- Subtask 1.5 – Comparison between single-train coal and coke fueled IGCC power plants
- Subtask 1.6 – Optimized coal fueled 1,000 MW IGCC power plant
- Subtask 1.7 – Optimized single-train coal to hydrogen plant
- Subtask 1.8 – Review the status of warm gas clean-up technology applicable to IGCC plants
- Subtask 1.9 – Discuss the Value Improving Practices availability and reliability optimization program

During the Subtask 1.3 optimization effort the project team applied Global Energy's design and operation experience coupled with Bechtel's design template approach and Value Improving Practices procedures to reduce plant costs. Specific goals were to lower total installed costs, shorten schedules, and reduce maintenance costs for a plant which is environmentally sound with very low air emissions. This should maximize the Net Present Value (NPV), and thereby create market opportunities for Global's E-GAS™ gasification technology.

This progress report summarizes the results of Subtask 1.3. The scope of Subtask 1.3 is to revise the Subtask 1.2 facility to develop an Optimized Petroleum Coke IGCC Plant producing steam and hydrogen for the adjacent petroleum refinery in addition to electric power. The plant is located at a generic U. S. Gulf Coast location adjacent to an existing petroleum refinery.

Section 2 of this report starts out by briefly describing the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant as a basis for comparison with the current work. This is followed by a description of the base case Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant design, input and output flows, emissions, and total installed cost; and compares these items with those of the non-optimized design. This case is designated

[1] "Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, August 2000.

as the Subtask 1.3 base case. Two additional alternate cases were developed for the Subtask 1.3 design to examine the effects of equipment sparing which also impact both plant cost and availability. The base case Subtask 1.3 design includes a spare gasifier vessel in each gasification train. The first alternate case is the minimum cost case which deletes the spare gasification vessel. The other alternate case is one that has an entire spare gasification train from the slurry tanks and pumps through the wet scrubber where the solids are removed from the syngas.

Section 3 highlights the major design improvements that were made during the Value Improving Practices exercise to improve the financial performance of the plant by reducing the total installed cost, increasing expected revenues, and improving the plant availability, and reducing the maintenance costs.

Section 4 describes the results of the financial analysis for the Subtask 1.3 Base Case plant and the two alternate Subtask 1.3 Optimized Petroleum Coke Coproduction Plants.

Section 5 summarizes the Subtask 1.3 results.

Appendix A to this report contains the design and cost information for the Optimized Petroleum Coke IGCC Coproduction Plant in more detail than is contained in the body of this report. The appendix includes:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the IGCC facility
- Artist's view of plant site
- Overall material, energy, and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

Appendix B contains the site plan for the alternate spare solids processing case.

Appendix C contains the financial model input parameters for the Subtask 1.2 and the Subtask 1.3 cases.

Section 2
Plant Design

2.1 Subtask 1.2 Non-optimized Plant Description

The non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant design was developed based on the Wabash River Repowering Project design. The primary purpose of this plant design was to provide a basis for optimizing the design of the Subtask 1.3 plant. The non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant was designed under the premise that the steam and hydrogen products that it produces can be sold to an adjacent petroleum refinery must have a high reliability. Hydrogen capacity was set based on the size of a typical steam methane reforming (SMR) system (~80 MMscfd), and the hydrogen reliability was set at >98% to match SMR operations and refinery needs. Because a single gasification train with backup natural gas firing can satisfy the refinery steam and hydrogen requirements by sacrificing electric power production, all critical parts of the plant were replicated to provide high reliability of a single gasification train. For example, the slurry preparation, slurry storage, slurry pumping and heating sections contain two duplicate trains each with sufficient capacity for the entire plant. The entire gasification area including the acid gas removal area, sulfur recovery facilities, and hydrogen production facilities consist of three duplicate trains each with a capacity of 50% of the total plant design capacity.[2] Figure 1A is a simplified train flow diagram showing the replication of various plant sections in the non-optimized plant. Figure 2 is a detailed block flow diagram of the non-optimized Subtask 1.2 facility showing the duplication of the major plant sections as well as flow rate information for the major feed and product streams and the clean syngas streams.

This plant is located on the U. S. Gulf Coast adjacent to a petroleum refinery. It sells steam, hydrogen, and fuel gas to the refinery, and gets it coke supply directly from the refinery by conveyor.

The complete design and performance of the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant has been described in a previous report.[3] Table 1 summarizes the major plant input and output streams. The plant consumes 5,249 t/d of dry petroleum coke and produces 395.8 MW of electric power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 367 t/d of sulfur. It also produces 99.6 MMscfd of a low Btu fuel gas (87 Btu/scf HHV) for sale to the adjacent petroleum refinery.

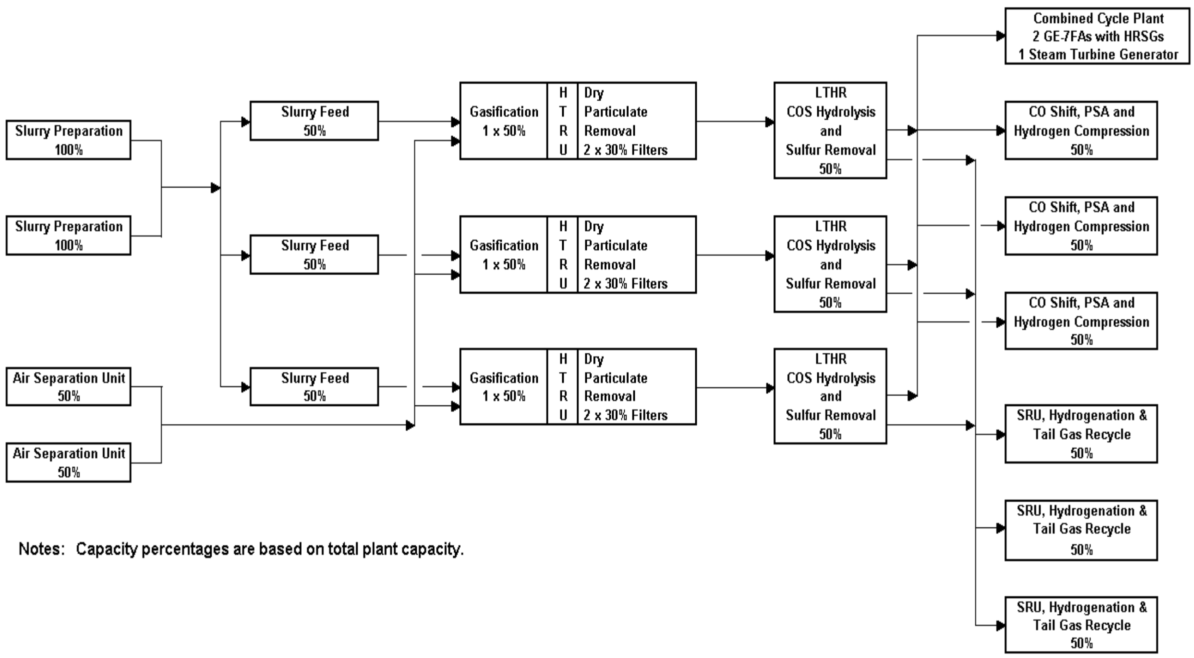
The Subtask 1.2 plant uses two GE 7FA gas turbines; the same gas turbine as used at the Wabash River facility. A modern and more efficient steam turbine that is appropriately sized for this application is used rather than the 1953 vintage steam turbine that was repowered at Wabash River. New petroleum coke receiving and storage facilities were designed to replace the coal facilities since the Wabash River Repowering Project used the existing facilities. New fresh water treatment facilities also were designed to handle the plant makeup river water. New waste water cleanup facilities also were designed to allow compliance with water discharge criteria and commingling of waster water with the refinery waste water outfall.

[2] Capacity references are to the total plant design capacity.
[3] Subtask 1.2 Progress Report, July 2000.

Figure 1A

Subtask 1.2 - Train Block Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

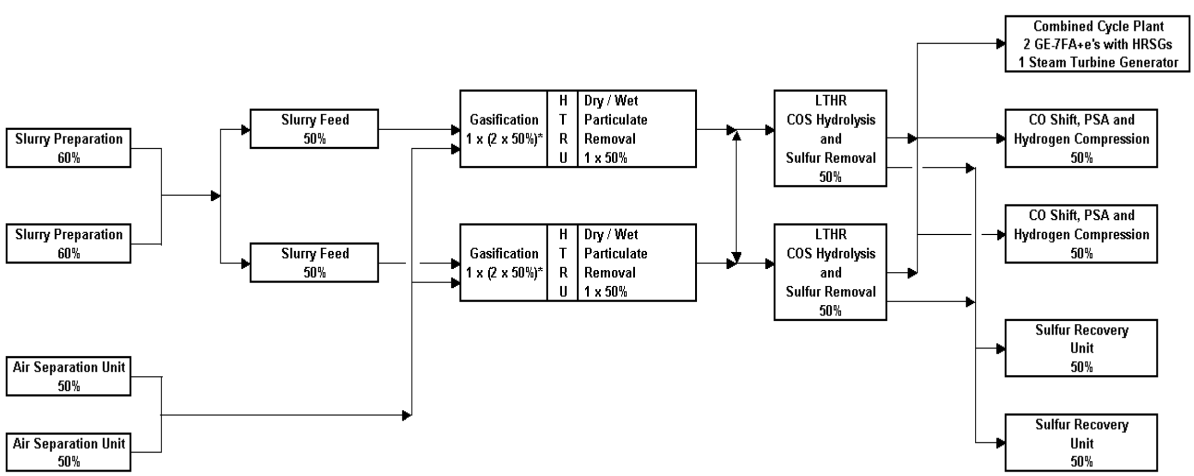


Notes: Capacity percentages are based on total plant capacity.

Figure 1B

Subtask 1.3 Base Case - Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

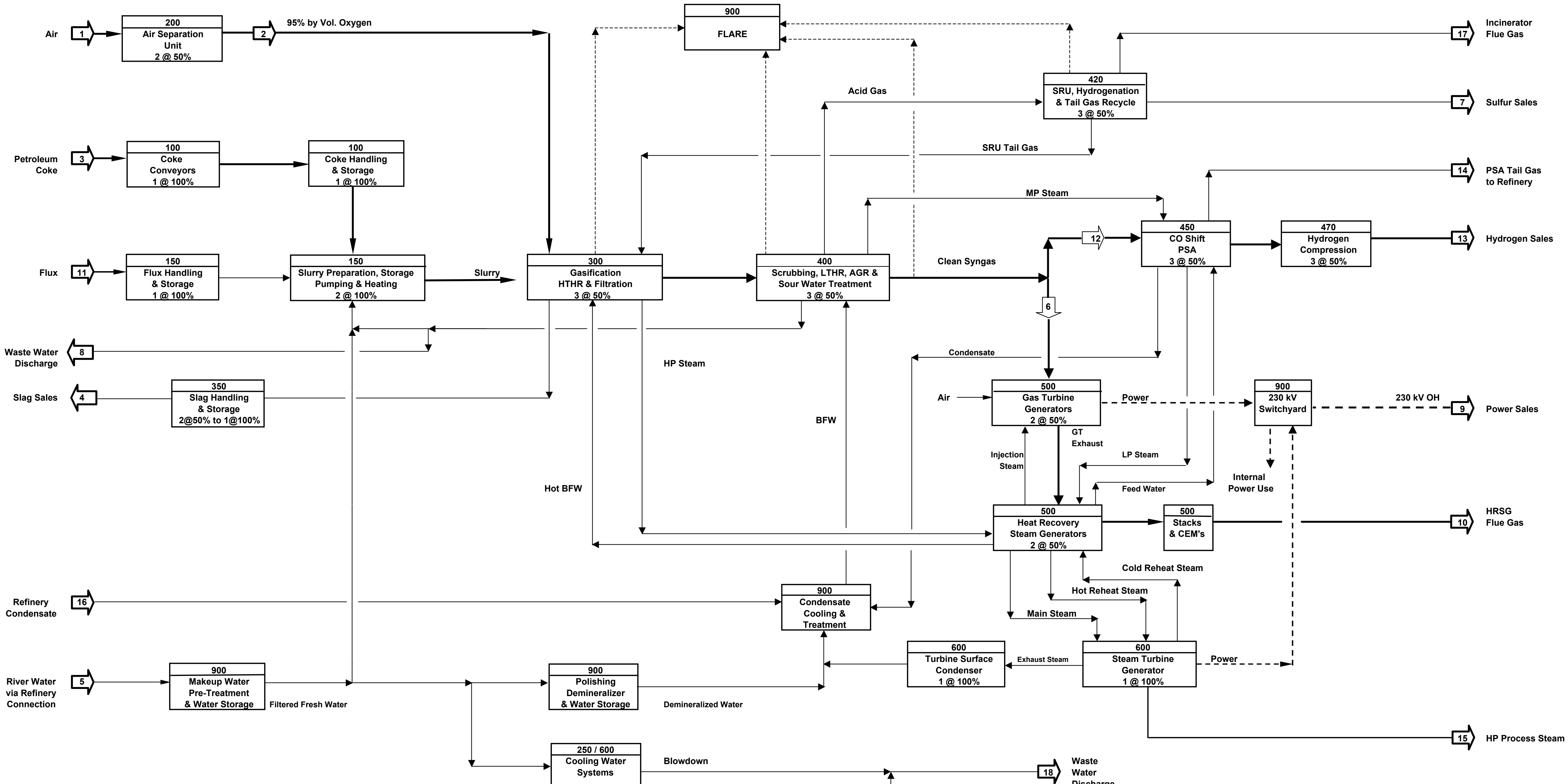


Notes: Capacity percentages are based on total plant capacity.
* Each gasification train contains a spare gasifier vessel.

Figure 2

Detailed Block Flow Diagram of the Subtask 1.2

Petroleum Coke IGCC Coproduction Plant



NOTE: Capacity Percentages are based on total plant capacity.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 27,129 Tons/Day	Oxygen 5,962 Tons/Day	Coke 5,249 Tons/Day	Slag 190 Tons/Day	Water 2,415,000 Lb/Hr	Syngas 861,915 Lb/Hr	Sulfur 367 Tons/Day	Water 28,340 Lb/Hr	Power 395,800 kWe	Flue Gas 7,572,000 Lb/Hr	Flux 107 Tons/Day	Syngas 342,960 Lb/Hr	Hydrogen 79 MMSCFD	Tail Gas 100 MMSCFD	HP Steam 980,000 Lb/Hr	Condensate 686,000 Lb/Hr	Flue Gas 10,956 Lb/Hr	Waste 479,000 Lb/Hr			
Nominal Pressure - psig	Atmos.	540	NA	NA	50	320	NA	62	NA	Atmos.	NA	320	1000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	NA	NA	70	530	NA	105	NA	243	NA	530	120	110	750	190	500	71			
HHV Btu/lb	NA	NA	14,848	NA	NA	4,123	NA	NA	NA	NA	NA	4,123	NA	909	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	14,548	NA	NA	3,914	NA	NA	NA	NA	NA	3,914	NA	801	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,495	NA	NA	3,553	NA	NA	NA	NA	NA	1,414	NA	363	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	6,364	NA	NA	3,374	NA	NA	NA	NA	NA	1,342	NA	320	NA	NA	NA	NA			
Notes	Dry Basis	95% O2	Dry Basis	15%Wtr.	4,830 GPM	to GT	Sales	57 GPM	230 kV			for H2	Sales	Sales	Sales	Return		958 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure 2

Subtask 1.2

PETROLEUM COKE IGCC COPRODUCTION PLANT

BLOCK FLOW DIAGRAM

Revision 2

File:Fig 2 1.2 BFD R1.xls

February 21, 2002

Table 1
Design Input and Output Streams for the Non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant

Plant Input	
Coke Feed, as received, TPD	5,515
Dry Coke Feed to Gasifiers, TPD	5,249
Oxygen Produced, TPD of 95% O_2	5,962
Total Fresh Water Consumption, gpm	4,800
Condensate Return from the Refinery, lb/hr	686,000
Flux, TPD	107
Plant Output	
Net Power Output, MW	395.8
Sulfur, TPD	367
Slag, TPD (15% moisture)	190
Hydrogen, MMscfd	79.4
HP Steam, 700 psig/750^{o}F, lb/hr	980,000
Fuel Gas Export, MMscfd	99.6
MMBtu/hr, (HHV)	363

2.2 Subtask 1.3 Optimized Plant Description

The base case design for Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant was developed based on the non-optimized design of the Subtask 1.2 plant. This plant also is located on the U. S. Gulf Coast adjacent to a petroleum refinery. However, several basic design changes were made for the optimized case, namely

1. The GE 7FA gas turbines were replaced by newer GE 7FA+e combustion turbines that have a higher capacity and higher thermal efficiency with lower NOx and CO emissions.
2. The low Btu fuel gas is no longer exported to the refinery, but is instead used in the plant to make high pressure steam which is used to make additional electric power.
3. The post reactor residence vessel was deleted.
4. Hot gas cyclones followed by wet scrubbing system are used to remove particulates from the syngas rather than a dry char filter system similar to that used at Wabash River.
5. The gasifier was modified for full slurry quench from recycle gas quench which is used at Wabash River.
6. Equipment replication was removed unless it is economically advantageous to retain the extra equipment.
7. A dome, rather than silos, is used for on-site coke storage.
8. The maximum main steam and hot steam reheat temperatures were increased to improve the steam turbine efficiency.
9. The hydrogen plant was redesigned to be more efficient with improved heat recovery.
10. The number of gasification trains was reduced to 2 from 3, and a spare gasifier vessel was added to each train.

The complete design and performance of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant is given in Appendix A. Table 2 summarizes the Subtask 1.3 major plant input and output streams and compares them with those of Subtask 1.2, the non-optimized plant. The optimized plant consumes 5,399 t/d of dry petroleum coke (about 3% more than the non-optimized plant) using about the same size Air Separation Unit and produces 461.5 MW of net electric power (about 17% more than the non-optimized plant) while producing the same amount of hydrogen and steam. Part of the increased power production is attributable to a more efficient design, to higher performance equipment, and to the internal use of the low Btu fuel gas to make additional high pressure steam.

Table 2
Design Input and Output Streams for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Plant Input		
Coke Feed, as received, TPD	5,515	5,673
Dry Coke Feed to Gasifiers, TPD	5,249	5,399
Oxygen Production, TPD of 95% O_2	5,962	5,917
Total Fresh Water Consumption, gpm	4,800	5,150
Condensate Return from the Refinery, lb/hr	686,000	686,000
Flux, TPD	107	110.2
Plant Output		
Net Power Output, MW	395.8	460.7
Sulfur, TPD	367	371.8
Slag, TPD (15% moisture)	190	194.5
Hydrogen, MMscfd	79.4	80
HP Steam, 700 psig/750°F, lb/hr	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0
MMBtu/hr, (HHV)	363	0

Figure 1B is a simplified train flow diagram showing the replication of various plant sections in the base case Optimized Petroleum Coke IGCC Coproduction Plant. Figure 3 is a detailed block flow diagram of the base case optimized Subtask 1.3 facility showing the replication of the major plant sections as well as flow rate information for the major feed and product streams and the clean syngas streams.

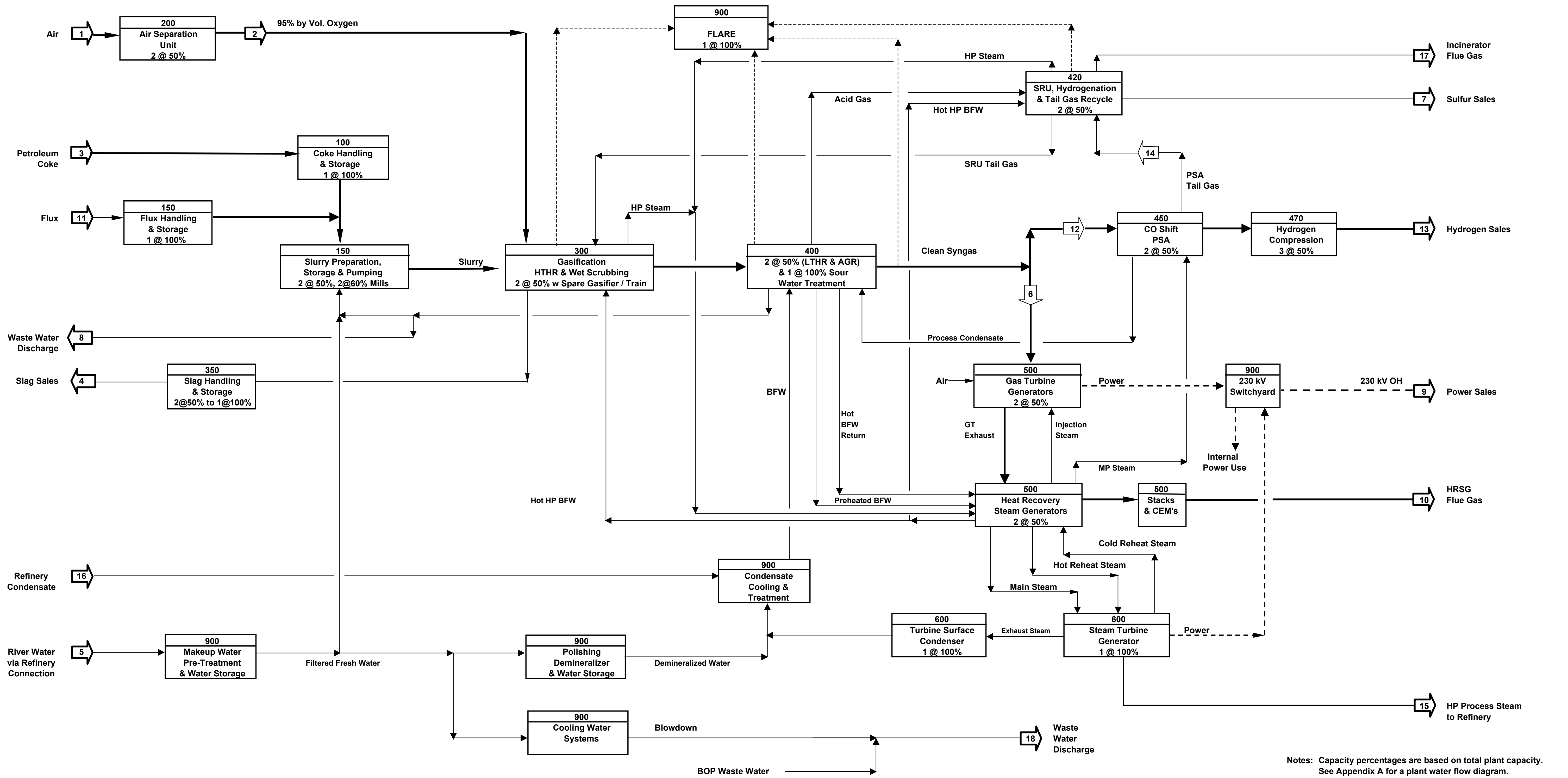
Compared to the non-optimized plant design, the amount of redundant equipment has been significantly reduced.

- The slurry preparation, pumping, and heating area has been reduced to two 50% trains with two 60% ball mills compared to the non-optimized case which has two 100% trains.
- The gasification, HTHR (high temperature heat removal), and particulate removal (wet scrubbing) contains two 50% gasifier trains each with a spare gasifier vessel compared to three 50% trains.

Figure 3

Detailed Block Flow Diagram of the Subtask 1.3

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.
See Appendix A for a plant water flow diagram.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coke	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	Flux	Syngas	Hydrogen	Tail Gas	HP Steam	Condensate	Flue Gas	Waste			
Flow	25,800	5,917	5,399	194.5	2,597,000	984,635	371.8	27,440	460,700	7,966,800	110.2	355,030	80	90.7	980,000	686,000	635,300	501,500			
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Tons/Day	Lb/Hr	MMSCFD	MMSCFD	Lb/Hr	Lb/Hr	Lb/Hr	Lb/Hr			
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	NA	350	1,000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	Ambient	180	70	530	332	80	NA	238	NA	530	120	115	750	190	500	71			
HHV Btu/lb	NA	NA	14848	NA	NA	3,848	NA	NA	NA	NA	NA	3,848	NA	782	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	NA	NA	NA	3,646	NA	NA	NA	NA	NA	3,646	NA	779	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,680	NA	NA	3,789	NA	NA	NA	NA	NA	1,366	1,083	282	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	Not Calc.	NA	NA	3,590	NA	NA	NA	NA	NA	1,294	917	281	NA	NA	NA	NA			
Notes	Dry Basis	5580 O2	Dry Basis	15%Wtr.	5,194 GPM	To GT	Sales	55 GPM	230 kV			For H2	Sales	360 MLb/hr	Sales	Return		1,003 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure 3

Subtask 1.3

OPTIMIZED PETROLEUM COKE IGCC

COPRODUCTION PLANT

BLOCK FLOW DIAGRAM

File: Fig 3 1.3 BFD R1.xls February 21, 2002

- The three 50% trains in the low temperature heat removal (LTHR), acid gas removal (AGR), and sour water treatment areas have been reduced to two 50% trains for the LTHR and AGR areas, and a single 100% sour water treatment area.
- The CO shift and PSA (hydrogen production area) contains two 50% trains compared to three in the non-optimized plant.
- The hydrogen compression area still contains three 50% hydrogen compressors because of their high maintenance requirements.
- The three 50% trains in the sulfur recovery unit (SRU), hydrogenation, and tail gas recycle area has been reduced to two 50% trains for the optimized plant.
- Minor reductions of replicated and unnecessary equipment were made in other areas not mentioned above.

During the Value Improving Practices procedures, the Process Availability Modeling studies suggested that a couple of alternate cases could be better than this base case depending upon the costs of replicating the gasification train and/or the gasification reactor vessels. Therefore, this case is designated as the base case, and two alternate cases were developed. These alternate cases are described in the next two subsections, 2.3 and 2.4.

As a result of the Value Improving Practices effort, significant changes were made in the gasification area while developing the Subtask 1.3 optimized plant design from the Subtask 1.2 non-optimized plant design. In the Subtask 1.2 design, there are three identical and parallel gasification trains with each train having a single gasification reactor vessel. Only two trains will be operating at any one time with the third train acting as a spare. When maintenance work is required on an operating train, it is shut down for repairs, and the spare train is placed on-line. When the repairs are completed, that train now becomes the spare train. Normal annual scheduled train maintenance is expected to require two twenty-day outage per year, and one twelve-week outage for refractory replacement every other year. During this refractory replacement, the normal twenty-day outage maintenance can be performed. Thus, the expected annual scheduled maintenance outages averages out to 62 days/year, or almost 9 weeks.

In the Subtask 1.3 optimized design, there are only two identical and parallel gasification trains, but each train contains a spare gasification reactor vessel that is not connected to the operating section. When it is necessary to replace the refractory in a reactor, the train is shut down, and the piping is rearranged to place the spare reactor in service and completely disconnect the previous operating from the operating areas of the plant. The piping change-out time is expected to require about two weeks. Simultaneously, the normal outage maintenance is performed. When completed, the train is started up with the previously spare reactor vessel in service. Since the reactor vessel requiring refractory replacement is now completely disconnected from the operating section, scheduled refractory replacement in the idle reactor can be done while the plant is running.

Because of various improvements to the Subtask 1.3 design, less scheduled maintenance is required than at the Wabash River facility, and the outage period can be shortened from twenty days to two weeks. Thus, the expected annual maintenance per train consists of only two two-week periods, or only four weeks per year.

Other significant design changes from the Subtask 1.2 design involve the syngas processing. In Subtask 1.2, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section, and dry char filters remove particulates. A wet scrubbing column downstream of the dry char filters removes chlorides. In Subtask 1.3, the post reactor residence vessel has been eliminated, and the hot syngas goes directly to the HTHR section. Most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. The remaining particulates and chlorides, as well, are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before they are recycled back to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

Emissions performance of the non-optimized and Optimized Petroleum Coke IGCC Coproduction plants are similar as shown in Table 3. The reduced NOx and CO emissions of the optimized plant are the result of steam dilution and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which also has a higher power output and a higher thermal efficiency.

Table 3
Total Emissions Summary for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,587,700	8,602,300
Emissions		
SOx ppmvd	20	24
SOx as SO_2, lb/hr	306	385
NOx, ppmvd	30	14
NOx as NO_2, lb/hr	325	166
CO, ppmvd	17	15
CO, lb/hr	111	105
CO_2, lb/hr (see note)	1,019,000	1,438,400
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	99.5	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

The Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant occupies a site area of about 51 acres compared to the non-optimized Subtask 1.2 case which occupies about 71 acres. This is a reduction of 29% in site area.

Table 4 compares the installed cost of the base case Subtask 1.3 optimized plant with the Subtask 1.2 non-optimized plant.

Table 4
Total Installed Costs of the Optimized and
Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Plant Area		
Solids Handling	12,949,000	8,012,000
Air Separation Unit	121,187,000	106,857,000
Gasification	540,956,000	297,968,000
Hydrogen Production	60,981,000	42,931,000
Power Block	226,371,000	230,221,000
Balance of Plant	30,756,000	78,050,000
Total	$ 993,200,000	$ 764,040,000

Note: Because of rounding, some column totals may not add to the total that is shown.

The estimated accuracy of the total installed cost estimate for Subtask 1.2 is on the order of +/-11%. This level of accuracy reflects a high degree of confidence based on the actual costs of the Wabash River gasification and air separation areas as a basis for adjusting the Subtask 1.2 scope. The estimated accuracy for the Subtask 1.3 optimized plant is on the order of +/-10%. This accuracy estimate is slightly lower because of the fact that a large number of current vendor quotes for the new and high priced equipment were obtained and that the power block costs are based on a recent Powerline™ Gulf Coast estimate.[4] These accuracy estimates apply only to the total cost and do not apply to the individual areas or parts.

Although both the Subtask 1.2 and Subtask 1.3 plant costs are mid-year 2000 costs, the Subtask 1.3 costs are more reflective of current market pricing. For the Subtask 1.3 plant, current vendor quotes were obtained for most of the new and high priced equipment, and the power block costs are based on the actual costs of a similar power project. Thus, they reflect current market conditions. Because of the current demand for gas turbines, the cost for the two combustion turbines appear high compared to historical data.

The Subtask 1.3 plant costs about 23% less than the non-optimized Subtask 1.2 plant. However, a side by side comparison of the plant area costs between Subtask 1.2 and Subtask 1.3 plants shows some striking differences. For all plant areas, a better breakdown between the individual process areas and the Balance of Plant grouping was made which put more costs in the Balance of Plant and reduced the cost of the three process areas. The Subtask 1.3 cost for the Solids Handling area is less than that for the Subtask 1.2 case because of a revised design approach and a better allocation of Balance of Plant items. The Air Separation Unit cost is based on a current vendor quote. The large reduction in the Gasification area cost is the result of a reduction in the number of gasification trains from 3 to 2, the reduction in installed replicated equipment, and the application of the VIP items to the gasification process. The Hydrogen Production area was completely redesigned and

[4] Powerline is a registered trademark of Bechtel Corporation.

optimized for Subtask 1.3. The increased Power Block cost for Subtask 1.3 is the result of market pricing for the gas turbines.

If the three-train Subtask 1.2 plant were to be built using the Subtask 1.3 optimized gasification train design, that plant would cost about 880 MM$. This is a savings of 113 MM$ or just over 11%, all of which essentially are in the gasification and balance of plant areas.

2.3 Subtask 1.3 Minimum Cost Plant Description

To further reduce the cost of the Optimized Petroleum Coke IGCC Coproduction Plant a minimum cost plant design was developed. Figure 4A is a simplified train flow diagram showing the replication of various plant sections in the Subtask 1.3 Minimum Cost Plant. In this design, the spare reactor vessel was removed from each of the two parallel gasification trains. There is only one gasification reactor vessel per train; the same number as in Subtask 1.2. For each train, the expected annual downtime for scheduled maintenance and refractory replacement is one two-week period and one six-week period for refractory replacement for a total of eight weeks per year.

Because the only change between this case and the Subtask 1.3 Base Case, which is described in the previous section, is the elimination of the spare reactor vessel, the input and output stream flow rates and emissions performance will be the same as that for the Subtask 1.3 Base Case. However, because of lower availability, the annual power sales, annual hydrogen, steam and sulfur productions, and annual coke consumption will be lower.

The removal of the spare gasification reactor vessel from each processing train does not significantly alter the overall site plan so that the Minimum Cost plant also will occupy a site area of about 51 acres; the same area occupied by the Subtask 1.3 Base Case plant.

Section 4 discusses the plant availability and compares the annual plant capacity of the Subtask 1.3 Minimum Cost case with the Subtask 1.3 Base Case.

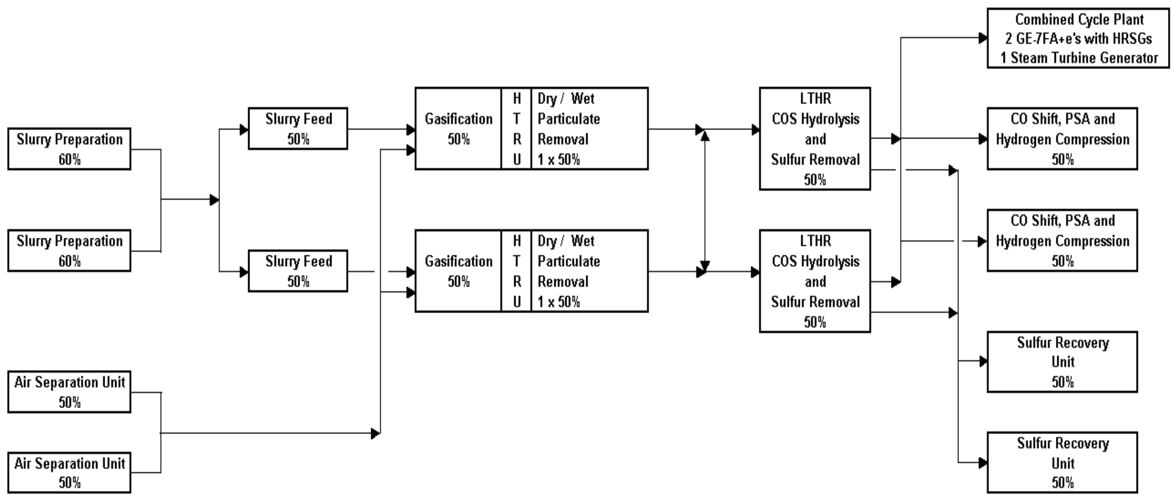
Table 5 compares the cost of the Subtask 1.3 Minimum Cost Plant with that of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant base case containing a spare reactor vessel in each train. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which is $ 18,000,000 less. This difference represents the total installed cost of removal of the two spare gasification vessels, one for each train, and a revised low cost particulate removal system. Thus, the minimum cost case is $ 18,000,000 less than the optimized Optimized Petroleum Coke IGCC Coproduction Plant base case.

A financial analysis comparing the economics of the Minimum Cost case with the Subtask 1.3 Base Case design is presented in Section 4.

Figure 4A

Subtask 1.3A Minimum Cost Case - Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

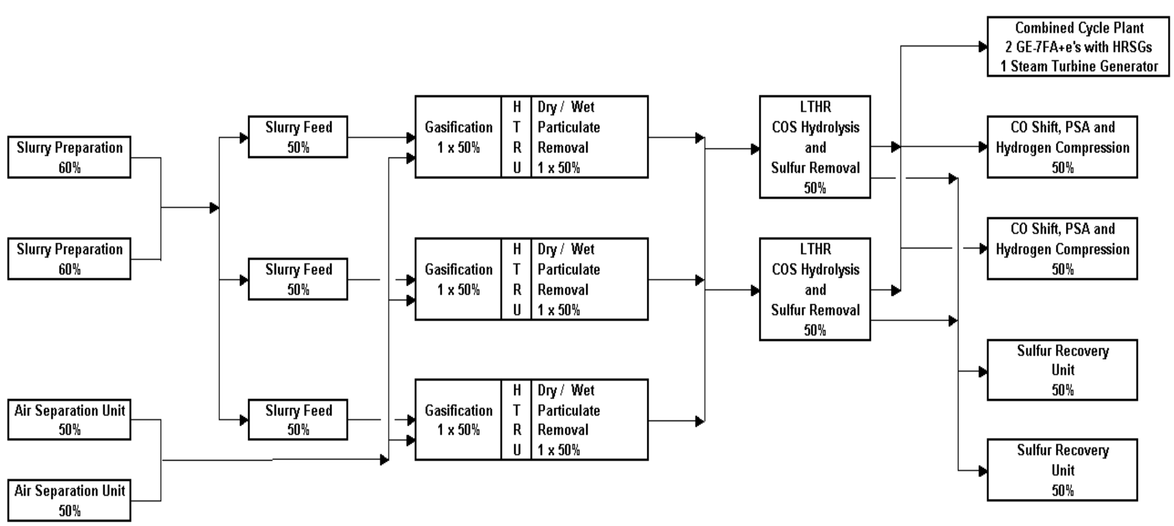


Notes: Capacity percentages are based on total plant capacity.

Figure 4B

Subtask 1.3S Spare Solids Processing Case - Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

Table 5
Total Installed Costs of the Subtask 1.3 Minimum Cost Case and Subtask 1.3 Base Case Optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.3 Base Case Optimized Plant	Subtask 1.3 Minimum Cost Plant
Plant Area		
Solids Handling	8,012,000	8,012,000
Air Separation Unit	106,857,000	106,857,000
Gasification	297,968,000	279,968,000
Hydrogen Production	42,931,000	42,931,000
Power Block	230,221,000	230,221,000
Balance of Plant	78,050,000	78,050,000
Total	$ 764,040,000	$ 746,040,000

Note: Because of rounding, some column totals may not add to the total that is shown.

2.4 Subtask 1.3 Spare Solids Processing Area Plant Description

To increase the availability of the Optimized Petroleum Coke IGCC Coproduction Plant, a plant design was developed in which there is a spare train for all the heated processing sections of the plant that process solids. Each train has only one gasification vessel as is the situation in Subtask 1.2 and in the Subtask 1.3 Minimum Cost case. Figure 4B is a simplified train flow diagram showing the replication of various plant sections in the Subtask 1.3 Spare Solids Processing Area Plant. In this design, there are three identical and parallel trains containing the slurry feed tanks and pumps, gasification vessel, high temperature heat removal equipment (HTRU), and the wet particulate removal system. Each train has a design capacity of 50% of the total plant capacity. This is the same gasification reactor vessel configuration that is used in Subtask 1.2. For each gasification train, the expected annual downtime for scheduled maintenance and refractory replacement is one two-week period and one six-week period for refractory replacement for a total of eight weeks per year. Whenever one train has to be shut down for maintenance, the spare train will be placed in service. Once that train is repaired, it will become the standby spare train until needed. Therefore, the annual maintenance per train will be reduced to two two-week periods per year for a total of four weeks per year.

The only change between this case and the Minimum Cost case and the Subtask 1.3 Base Case, which are described in the previous sections, is the addition of the spare solids processing train. Thus, the input and output stream flow rates and emissions performance of this option will be the same as those of the Subtask 1.3 Base Case. However, because of the higher availability, the annual power sales, annual hydrogen, steam and sulfur productions, and annual coke consumption will be higher.

The Subtask 1.3 Spare Solids Processing plant occupies a site area of about 52 acres which is a 2% increase compared to the Subtask 1.3 Base Case plant which occupies about 51 acres. This extra area is required for the addition of the third solids processing train adjacent to another one. Appendix B contains a site plan for the Subtask 1.3 Spare Solids Processing Plant.

Section 4 will discuss availability and compare the annual plant capacity of the Subtask 1.3 Spare Solids Processing Case with the other cases.

Table 6 compares the cost of the Subtask 1.3 Spare Solids Processing Plant with that of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant Base Case containing a spare reactor vessel in each train. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which costs $ 48,530,000 more. This difference represents the difference in total installed cost of the spare solids processing train and the removal of the two spare reactors from the base case design. Thus, the spare solids processing case costs $ 48,530,000 more than the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant Base Case. The Spare Solids Processing Case costs 66.5 MM$ more than the Minimum Cost case

Table 6
Total Installed Costs of the Subtask 1.3 Spare Solids Processing Case and Subtask 1.3 Base Case Optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.3 Base Case Optimized Plant	Subtask 1.3 Spare Solids Processing Plant
Plant Area		
Solids Handling	8,012,000	8,012,000
Air Separation Unit	106,857,000	106,857,000
Gasification	297,968,000	346,498,000
Hydrogen Production	42,931,000	42,931,000
Power Block	230,221,000	230,221,000
Balance of Plant	78,050,000	78,050,000
Total	$ 764,040,000	$ 812,569,000

Note: Because of rounding, some column totals may not add to the total that is shown.

Compared to the Subtask 1.2 non-optimized plant, the Subtask 1.3 Spare Solids Processing Plant costs about 180 MM$ or about 18% less. About 100 MM$ of these savings are in the gasification and balance of plant areas with the remainder with the remainder coming from the elimination of the third parallel trains in the LTHR, COS hydrolysis, sulfur removal, sulfur recovery, COS shift, PSA, and hydrogen compression areas.

A financial analysis comparing the economics of this case with the base case design and the minimum cost design is presented in Section 4.

Section 3
Value Improving Practices

Global Energy's design and operating experience coupled with Bechtel's design template approach and Value Improving Practices (VIPs) procedures were employed to improve plant performance and reduce plant cost for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant. Collectively, the VIPs are an organized approach to minimizing installed and life-cycle costs while optimizing the life of the facility. The Value Improving Practices procedures were implemented by bringing together Nexant and Bechtel's process, design, and construction experts, Global Energy's experts, and operating and maintenance personnel from the Wabash River plant to form evaluation teams. Each team was responsible for evaluating selected ideas, generated in the Value Engineering brainstorming sessions, according to their expertise.

The following subsections describe the VIP procedures, and their major results that were used in developing the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant.

3.1 Technology Selection

Technology Selection is a formal, systematic process for selecting various processes, inside or outside the company, that may be superior to those that are currently employed.

A. A GE 7FA+e gas turbine was selected to replace the older GE 7FA gas turbine because it is more efficient, has a higher power output, and produces lower NOx and CO emissions.

B. Steam conditions at the steam turbine for the power cycle of 1,450 psig and 1,050°F with a 1,050°F reheat temperature were selected over the Subtask 1.2 conditions of 1,450 psig and 1,000°F because simplified economics showed that this option has a 5 year payout.

C. Steam diliuent was selected for NOx control and power enhancement in the gas turbine because simple economics showed a 6 year payback period compared to longer payback times using nitrogen or CO_2 as diluent.

D. The Air Separation Unit (ASU) will use full size motor driven main air compressors in lieu of air extraction from the gas turbine or a steam driven air compressor.

E. The low-Btu tail gas from the PSA will be consumed within the plant to produce high-pressure steam for power production rather than to sell it to the refinery.

F. Replacing the two Subtask 1.2 concrete coke storage silos with a single geodesic dome coke storage facility, and using a pneumatic system for unloading the flux delivery trucks will reduce the plant cost by about 4 MM$.

G. Using a hybrid dry cyclone / wet scrubber particulate removal system rather than the dry char removal system for removing particulates from the syngas will increase the project NPV by about 42 MM$.

3.2 Process Simplification

Process Simplification is a disciplined analytical method for reducing investment costs (and often operating costs, as well) by combining or making unnecessary one or more chemical or physical processing steps. The major process simplification ideas were:

A. Removing the coke-slurry heaters

B. Using full slurry quench

C. Using a three-stage (instead of four-stage) Sulfur Removal Unit (SRU) with improved heat recovery

D. Using the PSA tail gas in the incinerator to make steam rather than exporting it to the refinery

E. Optimizing the HRSG heat recovery

F. Reducing the number of MDEA filters

G. Deleting the auxiliary boiler

3.3 Classes of Plant Quality

The Classes of Plant Quality procedure establishes the required quality of the facility needed to meet the business goals. This procedure determines the needed design allowance, redundancy, maintenance and sparing philosophy, and room for expansion. Application of this procedure eliminates the “nice to have” but not required features from the plant design. The Classes of Plant Quality team developed a table of specifications for the plant design.

3.4 Process Availability Modeling

Process Availability (reliability) Modeling uses computer simulation process tools to explore the relationship between maximum production rates, design parameters, and operational parameters to quantitatively assess the availability of all or part of a project to identify major contributors to scheduled and forced downtime.

Based on the actual availability data of various sections of the Wabash River Repowering facility, Process Availability Modeling and a financial analysis were used to evaluate sparing in the gasification and solids handling areas. These results will be discussed in detail in Section 4, Availability Analysis, and Section 5, Financial Analysis.

3.5 Design-to-Capacity

Design-to-Capacity evaluates the true required maximum capacity of each major piece of equipment relative to the desired overall facility capacity. Often equipment is designed with a "design factor" that results in larger equipment and additional excess capacity. The Design-to-Capacity procedure was used to remove these unnecessary design alllowances from the plant design based on the coal and coke operating experience at Wabash River.

The Wabash River Repowering Project plant was designed to operate on three different coals. This feedstock flexibility came at a price. Each section of the plant had to be sized for each of the three coals, and the design size that was selected was from the worst coal case. For example, the sulfur plant had to be sized for the coal that contained the highest sulfur content. Thus, when processing the other two coals with lower sulfur contents, the sulfur plant has excess capacity. This flexibility proved to be very beneficial when the Wabash River plant was switched over to processing petroleum coke since very little modifications were required to allow processing the coke.

The Subtask 1.3 optimized Petroleum Coke IGCC Coproduction Plant is designed for a single petroleum coke from a given refinery. Variations in the refinery crude slate will result in some variation in the coke properties, but these variations are expected to be relatively small compared to the possible variations in coal properties, and were neglected.

In this Design-to-Capacity VIP effort for the Subtask 1.3 plant, major pieces of equipment were resized on an individual basis. The basis for this procedure was the original equipment process data sheets. For each piece of equipment, one or more criteria was selected as the basis for sizing; for example, the selected criteria for the syngas recycle compressor was compressor horsepower. The original design values were then compared to the new requirements, and a new duty factor was calculated for each of the selected criteria. After the duty factors were calculated and for those items where more than one sizing criteria was determined, an evaluation was made, and the "worst case" value was selected.

3.6 Plant Layout Optimization, Constructability Review, and Schedule Optimization

Plant Layout Optimization formalizes the process of developing a plant layout that will satisfy the project needs at minimum life cycle costs. This VIP procedure considers:

- Accessibility during construction
- Accessibility during maintenance
- Accessibility during operations
- Minimization of interconnecting piping and electrical cable
- Safety
- Layout codes and regulations
- Provisions for modifications and expandability
- Integration with the surrounding community

Bechtel's plant layout and piping computer design program was used to model the Wabash River Repowering Project thereby establishing a basis for the design of the subsequent plants. After some minor adjustments, the amount of large bore and alloy piping predicted by the model matched that in the plant within 2%. For the Subtask 1.2, the non-optimized

Petroleum Coke IGCC Coproduction Plant, the model predicted 419,000 feet of pipe. For the Subtask 1.3 optimized Petroleum Coke IGCC Coproduction Plant, the model predicted that only 175,400 feet of pipe would be required. This is a reduction of 58% from Subtask 1.2, and a 75% increase from Subtask 1.1.

As a result of optimizing the plant layout, the Subtask 1.3 plant site was reduced to 51 acres from the 70 acres that the Subtask 1.2 plant occupied. A site plan and an artist's conception of the Subtask 1.3 plant are shown in Figures A2 and A3 of Appendix A.

A Constructability Review consists of an analysis of the design, usually performed by experience construction personnel, to reduce costs and/or save time during the engineering and construction phases. Bechtel's construction experts reviewed the plant layout and the actual construction operation of the Wabash River Repowering Project to develop a 42 month engineering and construction schedule (from project award) to commercial operation for the Subtask 1.3 plant. This is 10 months shorter than the 52 month construction schedule for Subtask 1.2. The detailed Subtask 1.3 engineering and construction schedule is shown in Figure A6 of Appendix A.

3.7 Predictive Maintenance and Operations Savings

Predictive Maintenance is a method of maintenance whereby equipment is monitored and repairs are effected as indicated before failure. Operating and maintenance personnel from the Wabash River Repowering Project spearheaded this VIP by examining historical plant data and combining that with proposed plant modifications and procedure revisions.

Forty-two ideas relating to Operations and maintenance were generated during the Value Engineering workshop. After evaluation, twenty-four items were accepted with a net capital cost reduction of $184,000 and a projected lower annual O&M cost savings of just over $1,000,000 per year based on present day costs. In addition, these items will contribute to increased plant availability.

3.8 Traditional Value Engineering

Value Engineering brainstorming sessions are designed to allow the free expression of ideas for plant modifications. Subsequently, these ideas are collected, organized, and evaluated. Value Engineering's goal is to obtain the lowest cost without sacrificing function, performance, or the ability of a facility to carry out its mission.

Lead by a trained Bechtel facilitator, a two day Value Engineering workshop was held in which all members of the VIP team attended. Two subsequent team meetings were held, each beginning with a brainstorming session, in which the evaluation of each of the VE items was reviewed by the appropriate evaluation team. In total, almost 300 Value Engineering items were generated and evaluated. About 50 of these ideas were accepted and applied to the design as discussed above.

Section 4
Availability Analysis

The common measures of financial performance, such as return on investment (ROI), net present value (NPV), and payback period, all are dependent on the project cash flow. The net cash flow is the sum of all project revenues and expenses. Depending upon the detail of the financial analysis, the cash flow streams usually are computed on annual or quarterly bases. For most projects, the net cash flow is negative in the early years during construction and only turns positive when the project starts generating revenues by producing saleable products. Therefore, the annual production rate is a key parameter in determining the financial performance of a project. The three previously described Subtask 1.3 cases reflect varying redundancy in design features. This variation effects the projected length of scheduled and forced outages, and consequently, the resulting annual production rates. Thus, a comparative availability analysis is required to predict the relative production rates and corresponding cash flows that are required to develop a meaningful financial analysis of these cases. Appendix J provides a more detailed description of the Availability Analysis studies that were done for the various subtasks.

4.1 Use of Natural Gas

The gasification trains in Subtask 1.2 plant and all three Subtask 1.3 plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to fully fire one combustion turbine. Thus, in this situation, natural gas is used to supplement the syngas and fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption in the plant also is reduced when one gasification train is not operating by the internal power it consumes and that of one air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

In the less frequent situation when only one syngas train is operating and only one combustion turbine is operable, backup natural gas also is used to fully load the available gas turbine and supply the design hydrogen and steam demands. In this situation, the export power produced by the plant is less than half the design rate.

In the least likely situation when both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire the turbine and produce only export electric power from both the combustion turbine and the steam turbine. In this case, the amount of export power will be greater than that of the design capacity of the plant because the internal power loads are greatly reduced.

The average daily natural gas rates are calculated as part of the availability analysis and are shown later in this section in Table 9. Natural gas usage during startup and during maintenance operations, such as for curing refractory, are not considered in the availability analysis calculations, but will be included in the operating and maintenance costs during the financial analysis.

4.2 Availability Analysis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[1] This information is summarized in Table 7. During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After three adjustments, this data was used to estimate the availability of the Subtask 1.2 and Subtask 1.3 Petroleum Coke IGCC Coproduction Plant designs. The first adjustment increased the availability of the air separation plant from the observed availability of 96.32% to the industry average availability of 98%. The second adjusted the availability of the first gasification stage to remove a slag tap plugging problem caused by an unexpected change in the coal blend to the gasifier. This adjustment is justified since a dedicated petroleum coke plant would be very unlikely to experience this problem. The third eliminated a short outage that was caused by an outage in the water treatment facility because sufficient treated water storage will be available to handle this type of outage.

Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant and for the three Subtask 1.3 optimized plant designs.[5] The top of Table 8 defines the four plant configurations that were considered.

The design for the Subtask 1.2 plant (shown in Figure 1A), the non-optimized Petroleum Coke IGCC Coproduction Plant, is based on the Wabash River Plant design with only those modifications required to satisfy the new design criteria associated with the:

- Location change to the U. S. Gulf Coast,
- Feedstock change from coal to petroleum coke,
- Larger plant size (5,249 tpd dry coke vs. 2,259 tpd dry coal),
- Coproduction of hydrogen for the adjacent petroleum refinery (79.4 MMscfd),
- Coproduction of steam for the adjacent petroleum refinery (980,000 lb/hr of 750^oF/700 psig steam),
- Addition of spare equipment to provide increased coproduct production reliability (>98%), and
- Elimination of redundant equipment, where possible.

As a result of this redesign effort, the non-optimized plant contains three parallel syngas generation, cleanup, hydrogen production, and steam generation trains; each with the capacity to produce 50% of design output (3x50). The spare gasifier vessel (that is present in the Wabash River design) was removed from each train. Two combustion turbines and a single steam turbine generate the electric power. In the rare situation when only a single gasification train is operable, with backup natural gas firing the plant will have sufficient capacity to satisfy the refinery hydrogen and steam demands at the expense of electric power production. Based on the Wabash River plant data, each train will require scheduled

[5] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304, August 1985.

Table 7
Wabash River Plant Availability Data During the Demonstration Period
(March 1, 1998 through Feb 29, 1999)[6]

Plant Section	Observed Availability	Adjusted Availability	Comments
SYNGAS GENERATION AREA			
Air Separation Unit	96.32%	98.00%	See note 1
Coke Handling	100.00%	100.00%	
Slurry Preparation	99.96%	99.96%	
Rod Mill	100.00%	100.00%	
Slurry Tank	99.96%	99.96%	
Gasification (through HTHRU)	83.42%	86.40%	See notes 3 and 4
First Stage	87.06%	90.16%	See note 2
Second Stage	97.82%	97.82%	
Raw Syngas Conditioning	100.00%	100.00%	
HTHRU	97.96%	97.95%	
Slag Handling	99.15%	99.15%	
Dry Particulate Removal	98.03%	NA	See note 5
Chloride Scrubbing System	99.87%	NA	See note 5
Dry / Wet Particulate Removal System		99.00%	Estimated
LTHR / AGR	99.62%	99.62%	
Low Temperature Heat Recovery (LTHR)	99.90%	99.90%	
Syngas Moistureization	100.00%	100.00%	
Acid Gas Removal	99.72%	99.72%	
Sulfur Recovery Unit	99.94%	99.94%	
POWER BLOCK			
Combustion Turbine	98.19%	98.19%	
Heat Recovery Steam Generator	97.40%	97.40%	
Water Treatment Facility	99.83%	100.00%	See note 5
Steam Turbine	99.88%	99.88%	

Notes:
1. Based on industry average value which allows for a derime outage every second operating year.
2. Removed slag tap plugging that resulted from an unexpected change in coal blend to the first stage gasifier in January 1999.
3. Expected operating improvements are projected to boost the availability of the Gasification (thru HTRU) to 93.0%. This compares the recent plant experience on petroleum coke for the 2000 calendar year where the availability was 94.5%.
4. For the Observed Availability, the 83.42% of the Gasification (thru HTRU) is the product of the following four items (83.42% = 87.06% * 97.82% * 100% * 97.96%).
5. The dry particulate removal system and the wet chloride scrubbing system used at Wabash River are replaced by a hybrid dry cyclone / wet scrubber particulate removal system in the Subtask 1.3 cases. This system consists of a hot cyclone, which removes most of the particulates from the syngas, followed by a wet scrubber column.
6. Assumes water storage can compensate for an unscheduled outage.

---

[6] "Wabash River Coal Gasification Repowering Project, Final Technical Report," U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000

Table 8
Subtask 1.2 and Subtask 1.3
Plant Configurations and Availabilities

Case Identification Case Description	**Task 1.2**	**Task 1.3** **Base**	**Task 1.3** **Minimum Cost**	**Task 1.3** **Spare Solids Processing**
Plant Section	Number of Trains and Section Capacity			
ASU	2x50	2x50	2x50	2x50
Coke Handling	1x100	1x100	1x100	1x100
Slurry Prep (note 3)	**3x50**	2x60	2x60	2x60
Slurry Feed	**3x50**	2x50	2x50	**3x50**
Gasification (though HTHRU) (note 4)	**3x50**	**2x50**	**2x50**	**3x50**
Slag Handling	1x100	1x100	1x100	1x100
Dry Particulate Removal	**3x(2x30)**			
Chloride Scrubbing System	**3x50**			
Wet Particulate Removal		**2x50**	**2x50**	**3x50**
LTHR/AGR	**3x50**	2x50	2x50	2x50
SRU	**3x50**	2x50	2x50	2x50
Hydrogen	**3x50**	2x50	2x50	2x50
Combustion Turbine	2x50	2x50	2x50	2x50
Steam Turbine	1x100	1x100	1x100	1x100
Scheduled Outages per Train	**16.99%**	**7.67%**	**15.34%**	**15.34%**
Spare Gasifier Vessels (1 per train)	**No**	**Yes**	**No**	**No**
Possible Syngas Availability, % (note 5)				
From Two Gasifiers (@100% rate)	84.74%	67.69%	55.42%	86.41%
From Only One Gasifier (@50% rate)	99.39%	98.00%	96.73%	99.58%
Equivalent Availability (note 6)	92.07%	82.85%	76.08%	93.00%
Net Syngas and Power Availability, %				
From Two Gasifiers (@100% rate)	77.41%	61.84%	50.63%	78.94%
From Only One Gasifier (@50% rate)	99.20%	97.81%	96.55%	99.39%
Equivalent Availability (note 6)	88.31%	79.83%	73.59%	89.17%
Equivalent Power Availability (notes 6 & 7)	94.58%	93.34%	92.35%	94.72%
Hydrogen and Steam Availability, %				
Equivalent **Steam** Availability (note 6)	99.20%	97.81%	96.55%	99.39%
Equivalent **Hydrogen** Availability (note 6& 8)	99.20%	96.84%	95.58%	98.40%

Notes:
1. Capacity percentages are based on the total plant design capacity.
2. Based on an average hydrogen plant availability of 99.0%.
3. For the Subtask 1.3 Base and Minimum Cost Cases, the ball mills are (2x60%), and for the Subtask 1.3 Spare Solids Processing Case, they are (3x60%).
4. The Subtask 1.3 Base Case has a spare gasifier vessel in each train.
5. This is the clean syngas availability without any downstream constraints on consumption or use of the syngas; e.g., when exporting syngas to a pipline.
6. Equivalent availability is the average annual capacity expressed as a fraction of the design capacity.
7. Assumes supplemental firing with natural gas (natural gas backup) to make maximum use of the combustion and steam turbines.
8. Adding a third 50% hydrogen plant will increase the 100% hydrogen availability to about that of the syngas availability from one gasifier.

outages amounting to 17.0% of the time for routine maintenance, repair, and periodic replacement of the gasifier refractory (62 days/yerar)

As shown at the bottom of Table 8, two gasifiers should be available 77.41% of the time, and only one should be available 99.20% of the time. The resulting equivalent syngas availability will be 88.31% (i.e.; syngas production expressed a fraction of the design capacity on an annual basis). Since only one operable train is required to satisfy the refinery hydrogen and steam demands, these items will have an equivalent availability 99.20%, essentially the same as that when one of the two gasifier trains is operating.

The Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 92.07%. On this basis, the plant will have an average daily dry coke consumption of 4,635 TPD dry basis or 88.31% of the design coke consumption of 5,249 TPD.

The Subtask 1.3 Base Case for the Optimized Petroleum Coke IGCC Coproduction Plant, as shown in Figure 1B, has been reduced to a two train gasification plant; each with the capacity to produce 50% of design output (2x50). However, a spare gasifier vessel has been added to each train to match the configuration of the Wabash River plant. When one gasifier vessel needs refractory replacement, the additional vessel can be placed in service, and the refractory replacement can be done while the train is operating with the previously spare vessel in service. This significantly reduces the scheduled maintenance time per train from 17.0% to 7.67% (62 to 28 days per year).

The dry char filter particulate removal system that is used at Wabash River and in the Subtask 1.2 design was replaced by a hybrid dry cyclone / wet scrubber particulate removal system. This new system is a two-step system that consists of a hot cyclone, which removes most of the particulates from the syngas, followed by a wet scrubbing system. The wet scrubbing system performs the dual purpose of removing both the particulates and chlorides from the syngas in a single step; thus eliminating the need for a separate chloride scrubbing system. The availability of this new system is estimated to be 99.0% compared to the 98.03% availability of the Wabash River dry char filters and the 99.87% availability of the chloride scrubbing system, excluding scheduled outages.

The syngas availability from both gasifier trains of the Subtask 1.3 Base Case for the Optimized Petroleum Coke IGCC Coproduction Plant should be 61.84, and from only one gasifier train it should be 97.81%. The resulting equivalent syngas availability will be 82.85%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 97.81%, essentially the same as that of a single gasifier train. The hydrogen availability will be only 96.84% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.2% lower than that of the Subtask 1.2 case. Because of the lower gasification train availability, significantly more backup natural gas is consumed to produce power. The steam availability is about 1.4% lower; and the hydrogen availability is about 2.4% lower. Although the Subtask 1.3 Base Case plant has lower availabilities, it has a significantly lower cost that should result in a higher Return on Investment (ROI).

The Subtask 1.3 Base Case Optimized Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 79.83%. On this basis, the plant will have an average daily dry coke capacity of 4,310 TPD dry basis or 79.83% of the design coke consumption of 5,399 TPD. This is an average of 325 TPD less coke than that of the Subtask 1.2 non-optimized plant because of a lower availability.

The Subtask 1.3 Minimum Cost Petroleum Coke IGCC Coproduction Plant, as shown in Figure 4A, is the same as the Subtask 1.3 Base Case except that the spare gasifier vessel in each gasification train has been removed. Thus, when a gasifier vessel needs refractory replacement, the entire train is shut down while the refractory is being replaced. This significantly increases the scheduled outage time per train from 7.67% for the base case to 15.34% for this case. This is a 1.65% improvement over the Subtask 1.2 plant.

The syngas availability from both gasifier trains of the Subtask 1.3 Minimum Cost should be 55.42%, and from only one gasifier train it should be 96.55%. The resulting equivalent syngas availability will be 76.08%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 96.55%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 95.58% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.0% lower than that of the Subtask 1.3 base case because more backup natural gas is used to make power. The steam availability is about 1.3% lower; and the hydrogen availability is about 1.3% lower. Although the Subtask 1.3 Minimum Cost plant has lower availabilities and a lower cost, it could result in a higher ROI.

The Subtask 1.3 Minimum Cost Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 73.59%. On this basis, the plant will have an average daily dry coke capacity of 3,973 TPD dry basis or 73.59% of the design coke consumption of 5,399 TPD. This is an average of 337 TPD less coke than that of the Subtask 1.3 Base Case plant.

The Subtask 1.3 Spare Solids Processing Petroleum Coke IGCC Coproduction Plant, as shown in Figure 4B, is the same as the Subtask 1.3 Minimum Cost case except that a third parallel gasification train has been added wherever solids are being processed. Thus, when a gasifier vessel needs refractory replacement, that entire train is shut down while the refractory is being replaced, and the spare train that was on standby is placed in service. This scheduled maintenance time per train for this case is 15.34%, the same as that for the Subtask 1.3 Minimum Cost Case.

The syngas availability from two gasifier trains of the Subtask 1.3 Spare Solids Processing Case should be 78.94%, and from only one gasifier train it should be 99.39%. The resulting equivalent syngas availability will be 93.00%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 99.39%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 98.40% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.4% higher than that of the Subtask 1.3 base case even though it uses less backup natural gas. The steam availability is about 1.6% higher; and the hydrogen availability is about 1.6% higher. Although the Subtask 1.3 Spare Solids Processing plant has higher availabilities, it has a higher cost that could result in a higher ROI.

The Subtask 1.3 Spare Solids Processing Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 89.17%. On this basis, the plant will have an average daily dry coke capacity of 4,8314 TPD dry basis or 89.17% of the design coke consumption of 5,399 TPD. This is an average of 504 TPD more coke than that of the Subtask 1.3 Base Case.

Table 9 compares the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.2 case and the three Subtask 1.3 cases. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and fuel gas product rates, and for the coke and flux feed rates. This is because these design rates are based on two trains running simultaneously. For the Subtask 1.2 and Subtask 1.3 Spare Solids cases, the calendar day rates are closest to the design rates because these cases have two operating and one spare train in the least reliable areas of the plant, and only two of them need to be running simultaneously to make the design rates. For all cases, the calendar day steam and hydrogen rates are a lot closer to the design rates since only one gasification train has to be operating for the plant to produce the design product rates.

The daily average natural gas rates shown in Table 9 are the lowest for the two cases where there are three parallel gasification trains, Subtask 1.2 and the Subtask 1.3 Spare Solids Processing case. This is because these cases have the highest availability of two trains. Thus, they, require the least amount of backup natural gas firing. The availability of the gasification trains in the Subtask 1.3 Base Case is higher than in the Subtask 1.3 Minimum Cost case because the former has a spare gasification reactor in each train. Consequently, the Base Case requires less natural gas usage than the Minimum Cost case.

Figure 5 compares the design and daily average coke consumptions for the Subtask 1.2 plant and for the three Subtask 1.3 cases. In all cases, the average daily coke consumption is significantly less than the design capacity. This difference is the least for the Subtask 1.3 Spare Solids Processing Case where it is only 585 TPD of dry coke less than the design capacity of 5,399 TPD, and it is the greatest for the Subtask 1.3 Minimum Cost Case where it is 1,426 TPD less. For the Subtask 1.3 Base Case, the average daily dry coke consumption is 1,090 TPD less than the design rate of 5,399 TPD.

Figure 6 shows the amount of time that various sections of the plant are operating. For Subtask 1.2,

- two gasification trains and two combustion turbines (code: 2Gs & 2 CTs) are operating about 77.4% of the time;
- only 1 gasification train and 2 combustion turbines (code: 1 G & 2 CTs) are operating about 13.4% of the time;
- only 1 gasification train and 1 combustion turbine (code: 1 G & 1 CT) are operating about 8.4% of the time; and
- only 1 combustion turbine (Code: 0Gs & 1CT) are operating about 0.6% of the time.

Table 9
Design and Daily Average Feed and Product Rates for Subtasks 1.2 and 1.3

	Subtask 1.2		Subtask 1.3			
				Daily Average		
Case	Design	Daily Average	Design	Base Case	Minimum Cost Case	Spare Solids
Product Rates						
Power, MW	395.8	374.3	460.7	430.0	425.4	436.4
Steam, Mlb/hr	980.0	972.2	980.0	958.6	946.2	974.1
Hydrogen, MMscfd	79.4	78.8	80.0	77.5	76.5	78.7
Sulfur, TPD	367.0	324.1	371.8	296.8	273.6	331.5
Slag, TPD	190.0	167.8	194.5	155.3	143.1	173.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0
Input Rates						
Coke, TPD	5,249	4,635	5,399	4,310	3,973	4,814
Flux, TPD	107	94.5	110.2	88.0	81.1	98.3
Natural Gas, MMBtu/d	0	10,099	0	20,000	26,977	9,303

Figure 5
Design and Daily Average Coke Consumptions

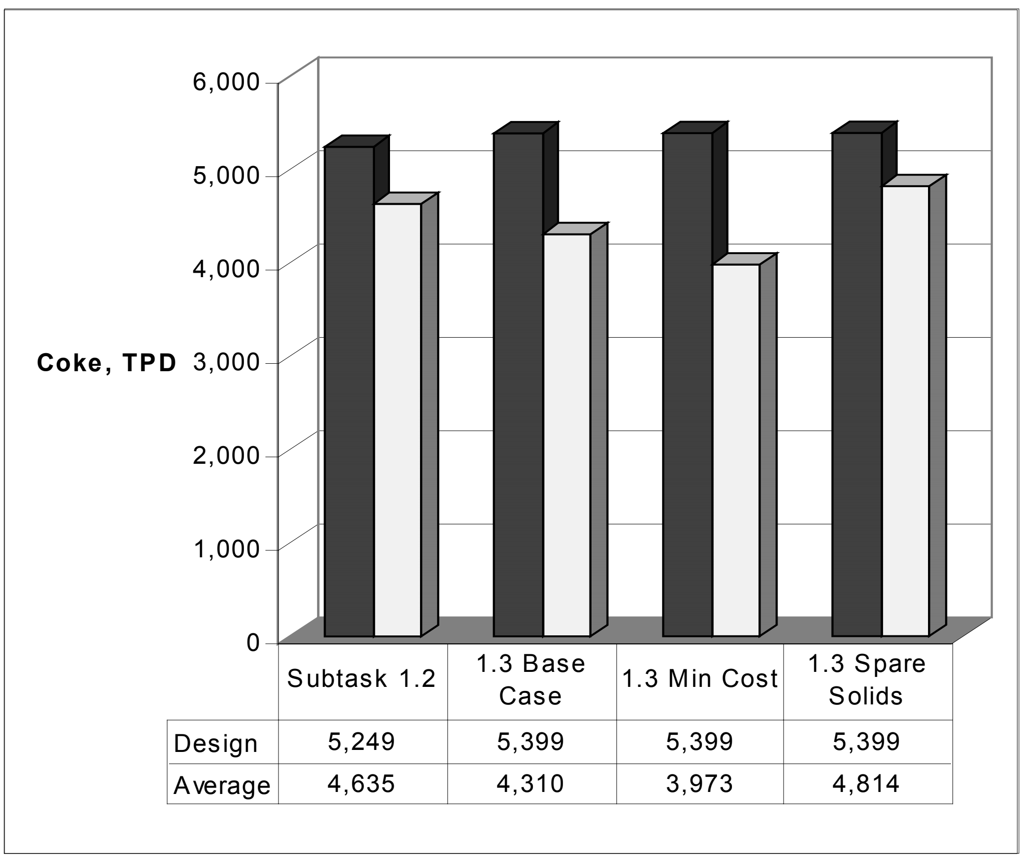


Figure 6
Equipment Availability

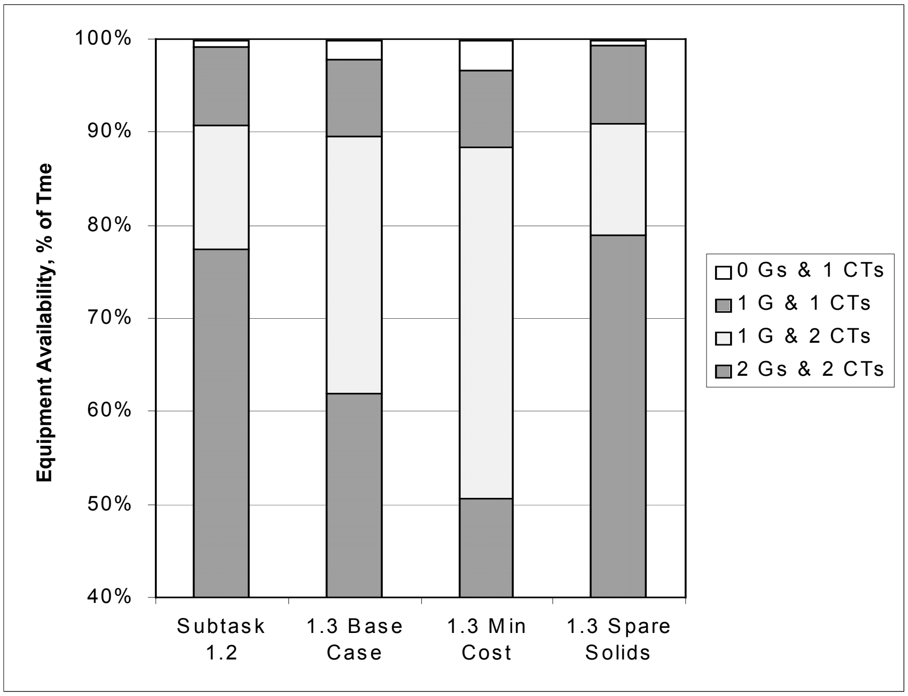
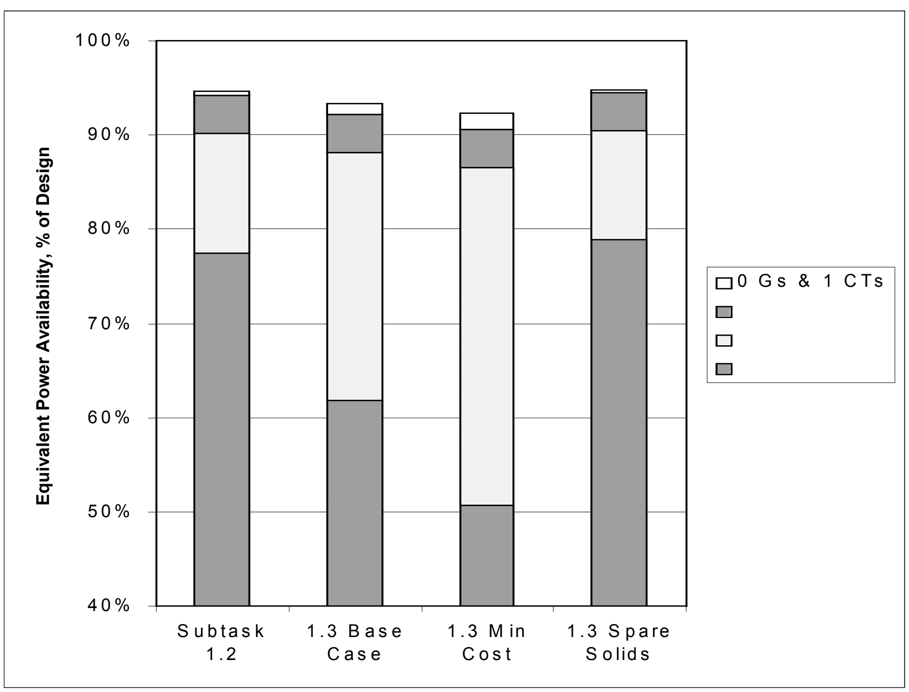


Figure 7
Equivalent Power Availability



This shows that for about 22.4% of the time, one or more gas turbines are using natural gas as a backup fuel because an insufficient amount of syngas is available. For the Subtask 1.3 Base Case, backup gas firing is used almost 38% of the time. For the Subtask 1.3 Minimum Cost case, backup gas firing is used about 49.2% of the time. The Subtask 1.3 Spare Solids Processing uses backup natural gas firing for about 20.9% of the time because the individual gasification trains have the highest availability. All four bars have the same height of 99.8%, which is the availability of one of the two combustion turbines.

Figure 7 shows the equivalent power availability as a function of the design rate produced by each mode of operation for the four cases. The height of each bar represents the annual equivalent power availability of each case as shown in Table 8. The Subtask 1.3 Spare Solids Processing Case has the highest total equivalent power availability of 94.7%, and the Subtask 1.3 Minimum Cost Case has the lowest equivalent power availability of 92.35%. For the Subtask 1.3 Base Case, about 31.5% of the design power is made when natural gas is being used, and for the Subtask 1.3 Spare Solids Processing Case, only about 15.8% of the power is being made when natural gas is being fired.

Section 5
Financial Analysis

The following financial analysis was performed using a discounted cash flow (DCF) model that was developed by Bechtel Technology and Consulting (now Nexant Inc.) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[7] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects.

5.1 Financial Model Input Data

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data that are directly related to the specific plant as follows.

Data Contained on the Plant Input Sheet
- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table C1 contains the plant data that are entered on the Plant Input Sheet for Subtask 1.2 and the three Subtask 1.3 cases. These data include the use of backup natural gas for firing the combustion gas turbines.

The Scenario Input Sheet contains data that are related to the general economic environment that is associated with the plant as well as some data that are plant related. The data on the Scenario Input Sheet are shown below.

Data Contained on the Scenario Input Sheet
- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Startup information

Table C2 contains the data that are entered on the Scenario Input Sheet for Subtask 1.2 and the three Subtask 1.3 cases.

For all four cases, the EPC spending pattern was adjusted to reflect forward escalation during the construction period since the EPC cost estimate is a instantaneous cost estimate based on mid-year 2000 costs.

[7] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

For the Subtask 1.3 cases, the construction period has been shortened to 42 months from the 48 month construction period that was used previously for the Subtask 1.2 financial analysis.

Finally, items that were excluded in the cost estimate, such as spares, owners cost, contingency and risk are included in the financial analysis.

5.2 Financial Model Results

Table 10 shows the basic discounted cash flow model results for Subtask 1.2 and the three Subtask 1.3 cases for the conservative price structure contained in Table C2 of Appendix C. With an electric power selling price of 27 $/MW-hr, the Subtask 1.3 Spare Solids Processing case has the highest after-tax ROI of 6.82% followed by the Subtask 13. Base Case with an ROI of 4.24%, and the Subtask 1.3 Minimum Cost case with an ROI of 1.43%. These cases are an improvement over the Subtask 1.2 case that has a negative ROI.

Table 10
Basic Financial Model Results

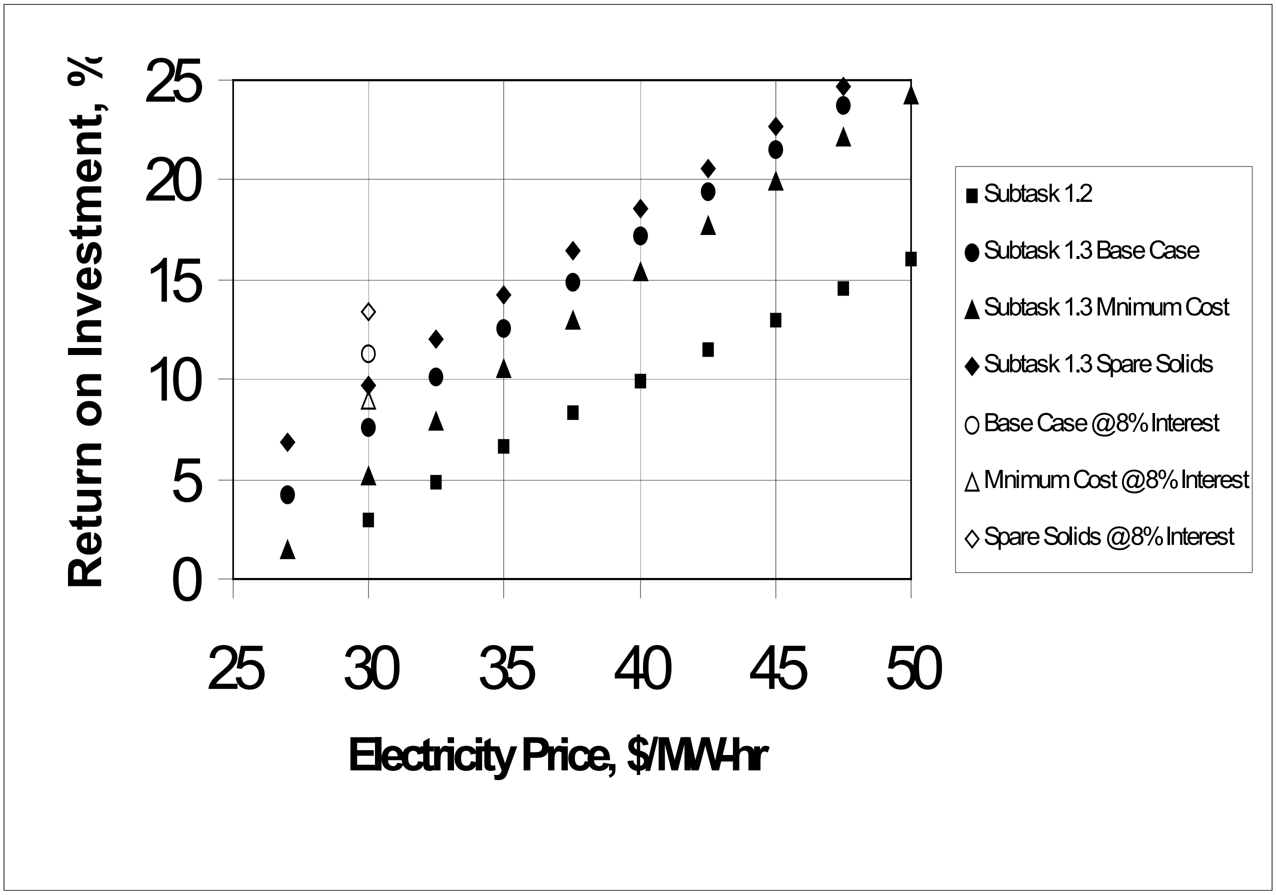
	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Processing Case
Return on Investment with 27 $/MW-hr Power	Negative	4.24%	1.43%	6.82%
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	34.45	36.49	32.48

The second line in Table 10 shows the required electric power selling price that will produce an after-tax ROI of 12%. The Subtask 1.3 Spare Solids Processing Case has the lowest required selling price of 32.48 $/MW-hr (or 3.248 cents/kW-hr). The Subtask 1.3 Base Case has the next lowest required power selling price of 34.45 $/MW-hr followed by the Subtask 1.3 Minimum Cost case that has a required selling price of 36.49 $/MW-hr. These three cases are a significant improvement over the Subtask 1.2 case which has a required power selling price of 43.36 $/MW-hr to produce a 12% after-tax ROI. Thus, the Subtask 1.3 Spare Solids Processing Case lowered the required power selling price by almost 11 $/MW-hr (or 1.1 cents/kW-hr).

Table 10 shows that the Subtask 1.3 Spare Solids Processing Case is the preferred Subtask 1.3 case because it has the highest return on investment and lowest required power selling price for a 12% after tax ROI even though it has the highest EPC cost.

Figure 8 shows the effect of electric power selling price on the after-tax ROI. As expected, the ROI is a strong function of the power price. The Subtask 1.3 ROIs are significantly better than those for Subtask 1.2 reflecting the effects of both the lower costs and higher gasification train availabilities of the Subtask 1.3 cases. The larger slopes of the Subtask 1.3 ROIs are a result of the lower capital costs of the Subtask 1.3 cases compared to the

Figure 8
Effect of Power Selling Price on the Return on Investment



Subtask 1.2 case. The Subtask 1.3 cases have similar slopes because they have closer installed costs, but here also, the slopes decrease as the installed costs increase. Thus, the Subtask 1.3 Minimum Cost case has the lowest cost and the greatest slope, and the Spare Solids Processing Case has the largest cost and the smallest slope. As seen from the figure, the Subtask 1.3 Spare Solids Processing Case must have a required electric power selling price of about 35.8 $/MW-hr for a 15% after-tax ROI.

The solid points in Figure 8 are based on an 80% loan at a 10% interest rate and a 3% financing fee. The open points are based on a 8% loan interest rate and the same 3% financing fee. Reducing the loan interest rate increases the after-tax ROI by about 3.7%. The ROI for the preferred Subtask 1.3 Spare Solids Processing Case increases to about 13.4%, and that for the Base Case increases to 11.3%.

Table 11 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.3 Base Case starting from a 12% ROI (with a power price of 34.45 $/MW-hr). Each item was varied individually without affecting any other item. The sensitivities of the other Subtask 1.3 cases will be similar. Most sensitivities are based on a $\pm$10% change from the base value except when either a larger or smaller change is used because it either makes more sense or it is needed to show a meaningful result. The power

Table 11
Sensitivity of Individual Component Prices and Financial Parameters for the Subtask 1.3 Base Case Starting from a 12% ROI (with a Power Price of 34.45 $/MW-hr)

	Decrease				Increase		
	ROI	Value	% Change	**Base Value**	% Change	Value	ROI
Products							
Power	8.60%	31.00 $/MW-hr	-10%	**34.45 $/MW-hr**	+10%	37.90 $/MW-hr	15.27%
Hydrogen	10.92%	1.17 $/Mscf	-10%	**1.30 $/Mscf**	+10%	1.43 $/Mscf	13.07%
Steam	11.30%	5.04 $/t	-10%	**5.60 $/t**	+10%	6.16 $/t	12.69%
Sulfur	11.93%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.07%
Slag	11.94%	-5 $/t	---	**0 $/t**	---	5 $/t	12.06%
Feeds							
Coke	13.75%	-5 $/t	---	**0 $/t**	---	5 $/t	10.25%
Natural Gas	12.60%	2.34 $/MMBtu	-10%	**2.60 $/MMBtu**	+10%	2.86 $/MMBtu	11.40%
Flux	12.04%	0 $/t	100%	**5 $/t**	+100%	10 $/t	11.96%
Financial							
Interest Rate	15.75%	8%	-20%	**10%**	+20%	12%	8.20%
Loan Amount	11.43%	72%	-20%	**80%**	+20%	88%	12.96%
Tax Rate	12.48%	36%	10%	**40%**	+10%	44%	11.48%

Note: Products and Feeds each are listed in decreasing sensitivity.

selling price is the most significant product price with a 10% increase resulting in a 3.27% increase in the ROI, and a 10% decrease resulting in a 3.40% decrease in the ROI. Hydrogen was the second most significant product price with a +10% increase resulting in a 1.07% increase in the ROI, and a 10% decrease resulting in a 1.08% decrease in the ROI. Steam was the next most significant product price with a +10% change resulting in a +0.69% increase in the ROI, and a –10% change resulting in a 0.70% decrease in the ROI. The effect of a ±10% change in the sulfur price from the base value of 30 $/ton changed the ROI by only ±0.07%. A slag price change of ±5.00 $/ton had an even smaller effect of only ±0.06%.

A change in the coke price of 5 $/ton from the base coke price of 0 will change the ROI by ±1.78% with an increase in the coke price decreasing the ROI and vice-versa. A change in the natural gas price of ±10% (or ±0.26 $/MMBtu) will change the ROI by ±0.60% with an increase in the gas price causing a decrease in the ROI and vice-versa. The ROI essentially is insensitive to the flux price with a 100% change from the base price of 5 $/ton only causing the ROI to change by 0.04%.
The interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the

ROI to 15.75% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.20%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.57% to 11.43%, and a 20% increase in the loan amount to 88% will increase the ROI by 0.96 to 12.96%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.48%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.52% to 11.48%.

Figure 9 shows the combined effect of changes in the natural gas price, steam, hydrogen, low Btu fuel gas, and power prices on the ROI for the four cases as a function of the product price index. Table 12, which is based on in-house correlations, shows the relationship between product price index and the five commodity prices.

Figure 9
Effect of Natural Gas Price and Associated Product Prices on the Return on Investment

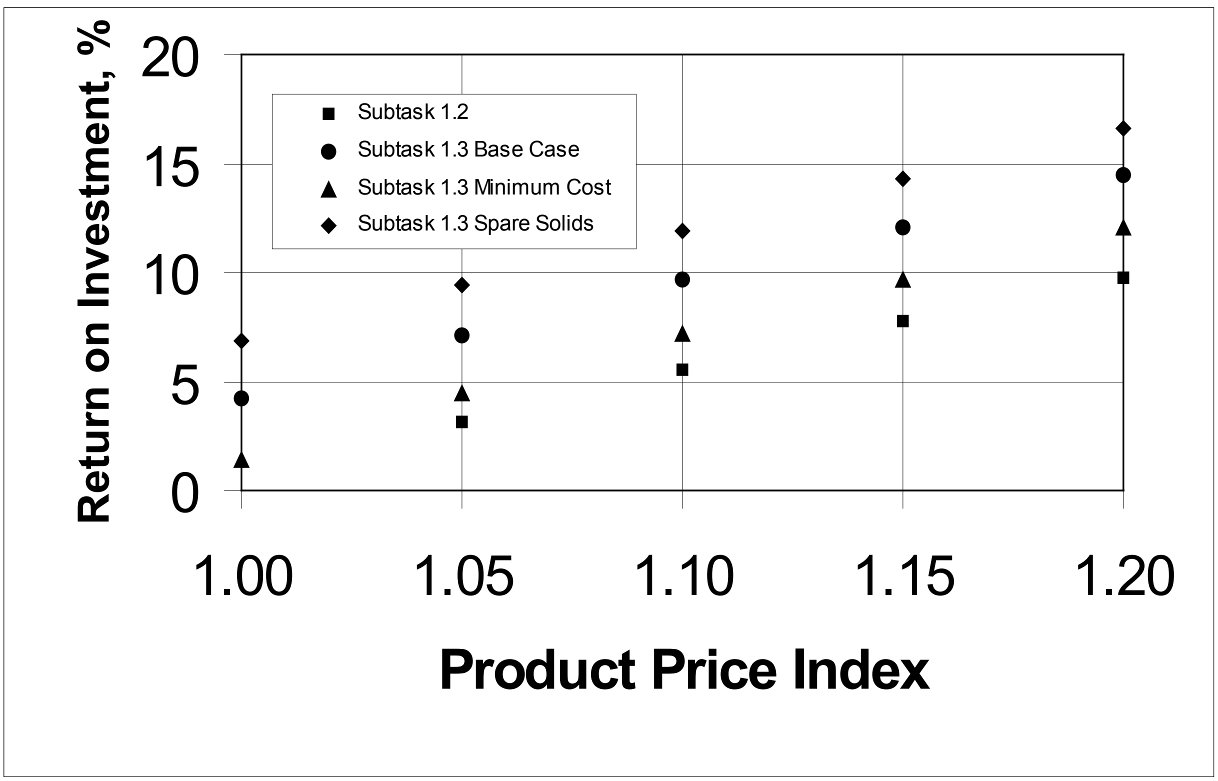


Table 12
Product Price Index and Commodity Prices

Product Price Index	Natural Gas, $/MMBtu	Power, $/MW	Hydrogen, $/Mscf	Steam, $/ton	Fuel Gas, $/Mscf
1.00	2.60	27.00	1.30	5.60	0.2274
1.05	2.73	28.35	1.43	5.88	0.2388
1.10	2.86	29.70	1.58	6.16	0.2501
1.15	2.99	31.05	1.69	6.44	0.2615
1.20	3.12	32.40	1.82	6.72	0.2729

This figure shows that with a 10% increase in the product price index, the natural gas price increases to 2.86 $/MMBtu, and the Subtask 1.3 Spare Solids Processing Case has an ROI of about 12.1%. At a gas price of 3.13 $/MMBtu corresponding to a 1.2 product price index, the Spare Solids Processing Case has an ROI of about 16.6%. At the same natural gas price, the Subtask 1.3 Base Case has an ROI of 14.5%.

5.3 Current Economic Scenario

Currently, the United States is in a period of low inflation, and as a result, interest rates are very low. Table 13 shows the effect of reducing the loan interest rate to 8% from 10% while still maintaining the same 3% upfront financing charge.

Table 13
Financial Model Results with an 8% Loan Interest Rate

	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Case
Return on investment with 27 $/MW-hr power	4.58	8.08	5.56	10.48
Required power selling price for a 12% return on investment	37.52	31.68	32.79	28.56
Return on investment with 27 $/MW-hr power and other prices indexed to 3.00 $/MM Btu Natural Gas	8.78%	11.86%	9.26%	14.40%
Return on investment with all prices indexed to 3.00 $/MM Btu Natural Gas	11.55%	15.99%	13.65%	18.15%

The first line of Table 13 shows the ROI at a 27$ MW power selling price at an 8% loan interest rate. The ROI for the Subtask 1.3 cases has increased by about 4% compared to the previous results at a 10% loan interest rate shown in Table 10. Subtask 1.2 now has a positive ROI of 4.58%.

The second line shows the required power selling prices for a 12% ROI. Compared to the previous results shown in Table 10, the required power prices for the Subtask 1.3 cases have dropped by 2.7 to 5.8 $/MW-hr. The Subtask 1.3 Spare Solids Processing Case now requires a power selling price of 28.56 $/MW-hr for a 12% ROI.

Presently, there are wide variations in the future projections for the price of natural gas. At the present time, a 3.00 $/MMBtu price for natural gas seems to be a reasonable value for economic projections. The next two lines of Table 13 show the effect of indexing the product prices to a 3.00 $/MM Btu natural gas price. The third line shows the return on investment at 27 $/MW-hr power price when the steam, hydrogen, and low Btu fuel gas are indexed to a 3.00 $/MM Btu natural gas price. This indexing of the product prices increases the ROI for all cases by about 4%.

The final line shows the ROI when all the product prices are indexed to a 3.00 $/MMBtu natural gas price. This increases the power price to 31.15 $/MW-hr. In this scenario, the

ROIs have increased by another 3 to 4%. The Subtask 1.3 Spare Solids Processing Case now has an ROI of 18.15%.

5.4 What-If Scenarios

Figure 10 shows the effect of the EPC cost on the after-tax ROI for the four cases with a 27 $/MW-hr power selling price. The farthermost right point in each series is the base point with the previously discussed estimated mid-year 2000 EPC cost. Moving to the left, the next point is a 2.5% reduction, followed by points with 5 and 7.5% cost reductions, respectively. The slopes of all four sets of data are similar. This figure shows that even with an additional 7.5% EPC cost reduction, the maximum ROI that can be obtained for the Subtask 1.3 Spare Solids Processing Case is just over 9%.

Figure 10
Effect of EPC Cost on the Return on Investment

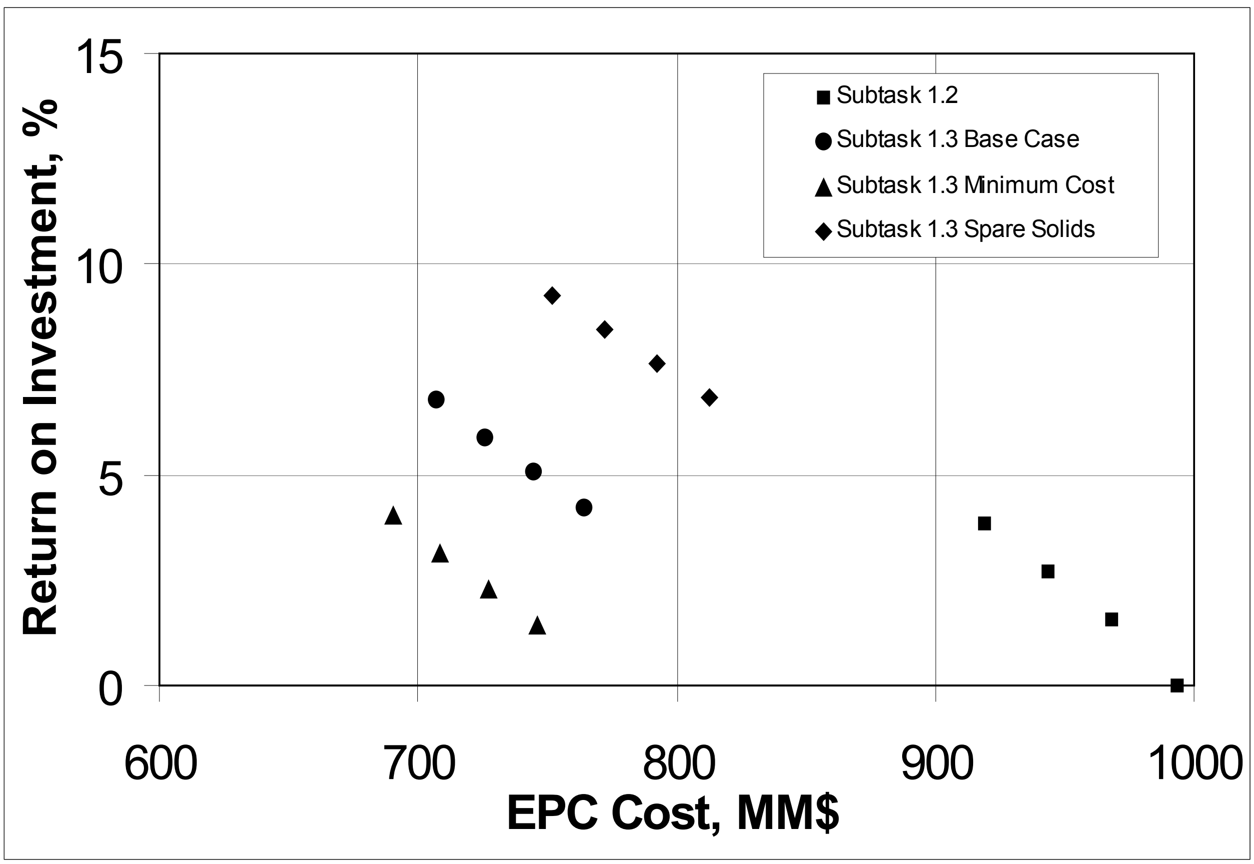
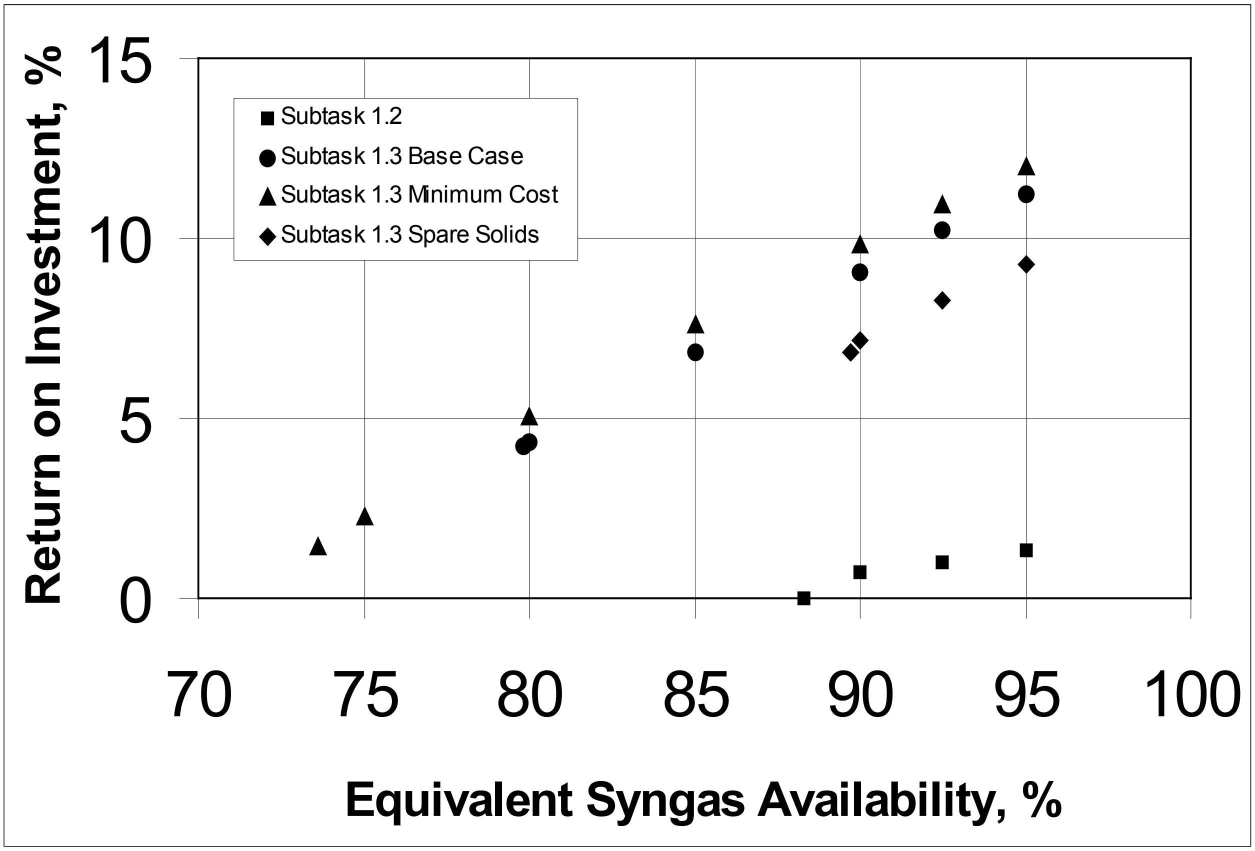


Figure 11 shows the effect of equivalent syngas availability on the ROI for the four cases. This set of curves can be called learning curves in that as the plant gains operating experience they should be able to increase the long term availability of the facility. The lowest leftmost point on each curve represents the base syngas availability as calculated in the Availability Analysis section based on Wabash River data. For expedience, the base availability of the Subtask 1.2 case is shown with a 0% ROI although it is slightly negative.

Figure 11
Effect of Equivalent Syngas Availability on the Return on Investment



The Subtask 1.3 Spare Solids Processing Case has the highest base equivalent syngas availability of 89.71% and an ROI of 6.8%. Increasing this to 92.5% would increase the ROI by about 1.4%. For the Subtask 1.3 Base Case, increasing the availability from the base value of 79.83% to 85% will increase the ROI by about 2.6% from 4.2% to 6.8%. The Subtask 1.3 Minimum Cost case has the lowest base equivalent syngas availability of 73.59%. Increasing this to 80.0% would increase the ROI by about 3.6% to 5.1%.

If through improved operating procedures and the development of more reliable pieces of processing equipment, the amount of unavailability of each of the Subtask 1.3 cases can be cut in half, then the:

- Spare Solids Processing Case would have an availability of 95%
- Base Case would have an availability of 90%
- Minimum Cost Case would have an availability of 87

At these availability levels, the three cases all would have ROIs in the 8 to 10% range. Therefore, other factors, such as annual coke processing capacity, hydrogen and steam availability, or other capital demands, could become an important factor in the selection of the appropriate process design.

5.5 Advanced Dry Particulate Removal System

In parallel with the study analysis described in the preceding text, Global Energy reviewed the operating history of the dry filters at the Wabash River plant, and the operating experience at other plants using similar dry particulate collection systems (filters with and without cyclones – TIDD, Demkolec, Rheinbraun). The primary objective was to reduce the cost of the dry filter system to or below that of the hybrid dry cyclone/wet filtration system, and to reduce the scheduled outage. This also would alleviate Global's concerns (based on operating experience previous to that at `Wabash River) about operating a wet scrubber and the testing of new filter media. Recent operating experience at Wabash River showed that the existing filters are operating very well on both coal and petroleum coke, with near 100% availability and a projected 1.5 years between scheduled outages. A review of the operating experience of others showed that a cyclone could be added upstream of the filter system, thereby significantly unloading the filters and greatly reducing the cost. Further analysis showed the following additional benefits of a cyclone / dry filter particulate removal system.

- The overall design is simpler and has less equipment.
- The proposed design is closer to current plant operations, and previous experience will be applicable.
- For the Base Case and Minimum Cost Case, the capital cost will be reduced by about 8 MM$.
- For the preferred Spare Solids Processing Case, the capital cost will be reduced by about 12 MM$.
- The syngas availability will be increased by about 0.5%.
- The net power output will be increased by 8.5 MW.
- The operating and maintenance costs will be reduced.
- There will be no impact on scheduled outages.

The net result of the above effects is a 1.5% increase in the ROI. Based on the expected benefits and assuming a successful testing and verification program, it is likely that the next plant will include a cyclone followed by a dry char filter system.

A Petroleum Coke IGCC Coproduction Plant using this advanced dry particulate removal system will be described further in a separate addendum/report.

Section 6
Summary

The objective of Subtask 1.3 is to develop an Optimized Petroleum Coke IGCC Coproduction Plant producing steam and hydrogen for an adjacent petroleum refinery starting from the non-optimized plant that was developed in Subtask 1.2. These IGCC plant systems build on the commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project.

The Subtask 1.2 Petroleum Coke IGCC Coproduction Plant produces 395.8 MW of export power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, 363 MMBtu/hr of a low BTU fuel gas, and 367 TPD of sulfur from 5,249 TPD (dry basis) of petroleum coke. For high reliability, this plant has three gasification and hydrogen production trains feeding two General Electric 7FA combustion turbines. It has an equivalent power availability of 99.58% when natural gas is used as a backup fuel. On a daily average basis, it will produce about 374 MW of power from 4,635 TPD of coke and 10,099 MMBtu/hr of natural gas. The estimated cost of this plant is $ 993,200,000 (mid-year 2000 basis). It will occupy about 72 acres.

Global Energy's design and operation experience coupled with Bechtel's design template approach and Value Improving Practices (VIP) procedures were employed to improve the plant performance and reduce the plant cost in developing the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant. The VIP procedures were implemented by bringing together Bechtel's process design and construction experts, Global Energy's experts, and operating and maintenance personnel from the Wabash River facility to form evaluation teams. The following VIP procedures were implemented during the VIP process:

- Technology Selection,
- Process Simplification,
- Classes of Plant Quality
- Process Availability Modeling
- Design-to-Capacity
- Plant Layout Optimization, Constructability Review, and Schedule Optimization
- Predictive Maintenance and Operations Savings
- Traditional Value Engineering.

The resulting base case Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant produces 460.7 MW of export power, 80.0 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 372 TPD of sulfur from 5,399 TPD (dry basis) of petroleum coke. This plant has only two gasification trains feeding two General Electric 7FA+e combustion turbines and two hydrogen production trains. For high reliability, each gasification train contains a spare gasification reactor that may be placed in service during the long outage when the refractory in the other reactor is being replaced. It has an equivalent power availability of 99.34% when natural gas is used as a backup fuel. On a daily average basis, it will produce about 430 MW of power from 4,310 TPD of coke and 20,000 MMBtu/hr of natural gas. It will satisfy all applicable emissions regulations. The estimated cost of this plant is $ 764,040,000 (mid-year 2000 basis). It will occupy about 51 acres.

The availability analysis suggested that the above Subtask 1.3 Base Case design may not be the economic optimum case. Therefore, two alternate Subtask 1.3 cases were developed; a Minimum Cost case, and a Spare Solids Processing Case in which there are three parallel trains from the slurry preparation area through the high temperature heat recovery and particulate removal area. In both of these alternate cases, the spare gasification reactor vessel has been eliminated. The three Subtask 1.3 cases have significant different availabilities, and consequently, significantly different daily average feed and product rates. The following table compares the design, daily average feed and product rates, and installed cost for the three Subtask 1.3 cases.

Subtask 1.3 Cases

		Daily Average		
	Design Flow Rates	Base Case	Minimum Cost Case	Spare Solids Processing Case
Product Rates				
Power, MW	460.7	430.0	425.4	436.4
Steam, Mlb/hr	980.0	958.6	946.2	974.1
Hydrogen, MMscfd	80.0	77.5	76.5	78.7
Sulfur, TPD	371.8	296.8	273.6	331.5
Slag, TPD	194.5	155.3	143.1	173.4
Fuel Gas, MMscf/d	0	0	0	0
Input Rates				
Coke, TPD	5,399	4,310	3,973	4,814
Flux, TPD	110.2	88.0	81.1	98.3
Natural Gas, MMBtu/hr	0	20,000	26,977	9,303
Plant Cost, MM$		764.04	746.04	812.57

Because of the low gasification train availability, the Subtask 1.3 Minimum Cost case process about 74% of the design coke capacity on a daily average basis, and consumes the most backup natural gas to produce power. The Spare Solids Processing case has the highest gasification train availability and process about 89% of the design coke capacity on a daily average basis, and consumes the least amount of backup natural gas to produce power.

All three Subtask 1.3 plant designs are less costly than the Subtask 1.2 design. The Subtask 1.3 Base Case will cost about 764 MM$ (mid-year 2000), 23% less than the non-optimized Subtask 1.2 plant. The Subtask 1.3 Spare Solids Processing Plant contains a spare gasification train and will cost about 813 MM$, an 18 % cost reduction compared to the non-optimized plant. The Subtask 1.3 Minimum Cost Plant will cost about 746 MM$. On the same complete three-train basis as the non-optimized plant, the cost reduction would be about 11%. In all the optimized cases, the savings essentially are in the gasification and balance of plant areas, and the savings range from 18 to 34%

A financial analysis using the discounted cash flow model that was developed by Bechtel Technology and Consulting (now Nexant Inc.) for the DOE was used to evaluate the relative economics of the three Subtask 1.3 cases and compare them with the non-optimized Subtask 1.2 case. The following table shows the results of this comparison

		Subtask 1.3 Cases		
	Subtask 1.2	Base Case	Minimum Cost Case	Spare Solids Processing Case
Return on Investment with 27 $/MW-hr Power	Negative	4.24%	1.43%	6.82%
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	34.45	36.49	32.48

All three Subtask 1.3 cases are an improvement over the Subtask 1.2 case. On a return on investment basis with 27 $/MW-hr power, the Spare Solids Processing case has the highest ROI of 6.82%, and the Minimum Cost case has the lowest ROI of 1.43%. The Subtask 1.3 Base Case is in between these two cases with a 4.24 % ROI.

Based on a current day economic scenario with product prices indexed to a 3.00 $/MMBtu natural gas price, the returns will be much better as shown below.

		Subtask 1.3 Cases		
	Subtask 1.2	Base Case	Minimum Cost Case	Spare Solids Processing Case
Return on investment with all prices indexed to 3.00 $/MM Btu Natural Gas	11.55%	15.99%	13.65%	18.15%

In the above scenario, the power price is 31.15 $/MW-hr, hydrogen price is 1.70 $/Mscf, 700 psig / 750^{o}F steam price is 6.46 $/ton, and the low Btu fuel gas is 0.2624 $/Mscf. The loan interest rate is 8% with a 3% upfront financing fee.

These results show that Spare Solids Processing case is the preferred configuration for the Subtask 1.3 Optimized Petroleum Coke Coprocessing Plant. This design for this plant was developed using state-of-the art equipment and technology to increase the operating efficiency, and reduce construction and operating costs. It is a simpler, more efficient, less polluting, IGCC coproduction plant which will have an expected ROI of over 18% under the current economic scenario.

Additionally, based on extensive review and Wabash River operating experience over the past two years with the dry char particulate filters and additional analysis of a cyclone plus dry filter system, Global Energy is confident that the cost of a dry particulate removal system can be significantly reduced. The new system would include a cyclone similar to that in the hybrid wet system, but the wet scrubber in each gasification train would be replaced by a single redesigned dry char filter. Recent operating experience on petroleum coke projects this dry filter system will have near 100% availability without any increase in the scheduled outage. For the preferred Spare Solids Processing Case, switching to this advanced dry particulate removal system will increase the plant availability by 0.5%, increase the power output by 8.5 MW, reduce the plant cost by 12 MM$, and reduce the O&M cost. Therefore, replacing the hybrid wet/dry particulate removal system with the advanced cyclone / dry filter system should increase the ROI by 1.5% for the above cases, thereby making dry char filtration the preferred particulate removal system for the next plant.

A Petroleum Coke IGCC Coproduction Plant using this advanced dry particulate removal system is described in the next appendix, Appendix D – Subtask 1.3 Next Plant.

Appendix C

Subtask 1.3 (Appendix A)

Optimized Petroleum Coke IGCC Coproduction Plant

Subtask 1.3 (Appendix A)
Table of Contents

<u>Figures</u>

Appendix A

Subtask 1.3 – The Optimized Petroleum Coke IGCC Coproduction Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest processing Illinois No. 6 coal. Subtask 1.2 developed a design and current cost for a petroleum coke IGCC coproduction plant producing electric power, hydrogen, steam, and fuel gas at a Gulf Coast location adjacent to a petroleum refinery

This appendix summarizes the results of Subtask 1.3. The scope of Subtask 1.3 is to convert the Subtask 1.2 facility into an Optimized Petroleum Coke IGCC Coproduction Plant producing electric power, hydrogen and steam at a Gulf Coast location adjacent to a petroleum refinery. The plant design was optimized using both Global Energy's petroleum coke experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures.

Bechtel and Global Energy implemented a project specific Value Improving Practices program to reduce the installed and operating costs associated with the plant to develop the design for the Optimized Petroleum Coke IGCC Coproduction Plant. The VIP team included process design and construction specialists from Bechtel, gasification experts from Global Energy, and operating and maintenance personnel from the Wabash River Repowering Project. The team implemented Value Improving Practices covering the following areas to improve the plant performance and return on investment.

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Design-to-Capacity
- Traditional Value Engineering
- Process Availability (Reliability) Modeling
- Plant Layout Optimization
- Constructability Review / Schedule Optimization
- Operation and Maintenance and Savings

This appendix contains the following design and cost information:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the IGCC coproduction plant
- Artist's view of the plant
- Overall material, energy and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

The following sections describe the results of Subtask 1.3, the design and cost estimate for the Optimized Petroleum Coke IGCC Coproduction Plant.

Section A2 contains the design basis for the Coke IGCC Coproduction Plant. Section A3 contains descriptions of the various sections of the plant. Section A4 summarizes the overall plant performance. Section A5 contains a listing of the major pieces of equipment within the plant. Section A6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the Optimized Petroleum Coke IGCC Coproduction Plant. The design basis for this plant essentially is the same as that of the non-optimized petroleum coke IGCC coproduction plant of Subtask 1.2 except that no fuel gas is exported to the petroleum refinery.

A.2.1 Capacity

The Optimized Petroleum Coke IGCC Coproduction Plant will process a nominal 5,400 TPD of delayed petroleum coke (dry basis) to produce syngas that will fully load two GE 7FA+e gas turbines at 70° F ambient, 60% relative humidity and 14.7 psia, and coproduce about 80 MMscfd of hydrogen. It also will export 980,000 lbs/hr of 750 psig / 700°F steam to an adjacent petroleum refinery.

A.2.2 Site Conditions

Location	Gulf Coast Refinery
Elevation, Ft	25
Air Temperature	
Maximum, °F	95
Annual Average, °F	70
Minimum, °F	29
Summer Wet Bulb, °F	80
Relative Humidity, %	60
Barometric Pressure, psia	14.7
Seismic Zone	0
Design Wind Speed, MPH	120

A.2.3 Feed

Type	Delayed Petroleum Coke	
	Dry Basis	As Rec'd
HHV, Btu/lb	14,848	14,132
LHV, Btu/lb	14,548	13,846
Analysis, Wt%		
Carbon	87.86	83.62
Hydrogen	3.17	3.02
Nitrogen	0.89	0.85
Sulfur	6.93	6.60
Oxygen	1.00	0.95
Chlorine	50 ppm	47 ppm
V & Ni	1900 ppm	1767 ppm
Ash	0.14	0.13
Moisture	NA	4.83
Total	100	100

A.2.4 Water

Cations	mg/l	As equivalent ppm of CaCO3
Calcium	8.4	21
Copper	0.01	
Iron	2.2	3.9
Magnesium	3.0	12.3
Manganese	< 0.06	
Molybdenum	< 0.01	
Potassium	2.0	2.6
Sodium	19.0	41.4
Zinc	0.01	0.02
Sodium (add to balance)	21.1	46.0
Total Cations		127

Anions	mg/l	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	61.0	50.0
Chloride	16.0	22.6
Sulfide	52.0	54.1
Nitrate - Nitrogen	0.7	0.6
Phosphate	0.6	
Fluoride	no data	
Chloride (add to balance)	0.0	0.0
Total Anions		127

Weak Ions	mg/l	As equivalent ppm of CaCO3
Ammonia Nitrogen	no data	
Total Silica	21.0	

Other Characteristics	mg/l	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	202	
Standard Conductivity	271	
Total Alkalinity		50
Total Hardness		33
Total Organic Carbon	12 to 15	
Turbidity	5 to 25	
PH	6.4 to 7.4	
Total Suspended Solids	10 to 60	

A.2.5 Natural Gas

Natural gas will be available for startup and for supplemental firing of the combustion turbines and HRSG. The natural gas will have a HHV of 1,000 Btu/scf and a LHV of 900 Btu/scf.

A.3 Plant Description

A.3.1 Block Flow Diagram

The Optimized Petroleum Coke IGCC Coproduction Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification

  - Slurry Preparation
  - Slag Handling
  - Gasifier/High Temperature Heat Recovery(HTHR)/Hybrid Dry Cyclone and Wet Scrubber Particulate Removal System
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block

  - Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator(STG)/Auxiliary Equipment

- Hydrogen Production

  - CO Shift
  - Pressure Swing Adsorption (PSA)
  - Hydrogen Compression

- Balance of Plant

Figure A1 is the block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the relative capacity of each train are noted on the BFD.

A.3.2 General Description

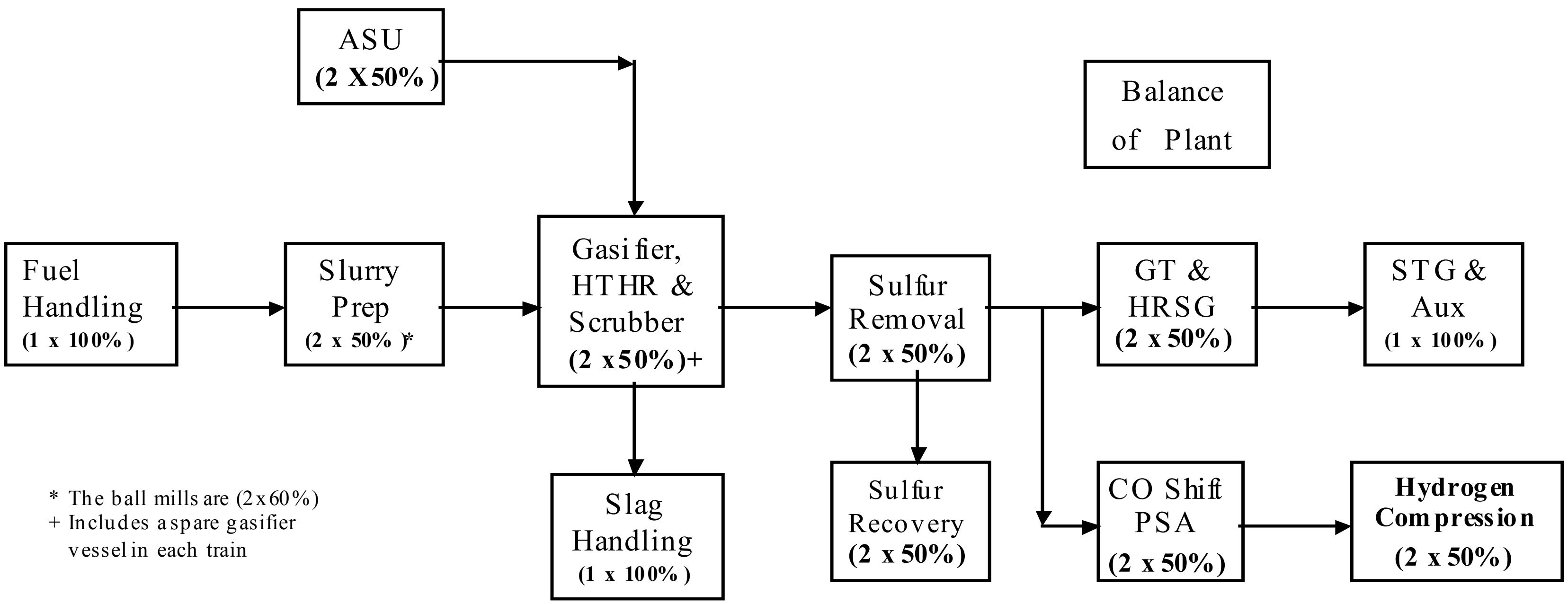
The plant is divided into the six distinct areas.

- Fuel Handling Unit
- Gasification Plant
- Air Separation Unit
- Power Block
- Hydrogen Plant
- Balance of Plant

Section A.3.3 describes the fuel handling facilities required for transferring petroleum coke from refinery battery limits to on site storage and conveying to the gasification plant.

Figure A1

OPTIMIZED PETROLEUM COKE IGCC COPRODUCTION PLANT SIMPLIFIED BLOCK FLOW DIAGRAM (Base Case)



Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two stage entrained flow gasifier to convert petroleum coke to syngas. The gasification plant includes several process units to remove impurities from the syngas. However, the dry filtration system used at the Wabash River plant to remove char from the syngas has been replaced by a lower cost wet scrubbing system.

Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95% purity oxygen stream is produced as the oxidant for the gasifier. The design is based on the Wabash River plant ASU.

Section A.3.6 describes the power block, which consists of two General Electric 7FA+e model gas turbines with generators and one steam turbine. The gas turbines use moisturized syngas and steam injection for NOx control.

Section A.3.7 describes the hydrogen plant, which consists of syngas CO shift units, Pressure Swing Adsorption (PSA) units, and hydrogen compressors.

Section A.3.8 describes the balance of plant (BOP). The BOP portion of the Optimized Petroleum Coke IGCC Coproduction Plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Optimized Petroleum Coke IGCC Coproduction Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were generated by the Comet model.

A.3.3 AREA 100 – Fuel Handling

The fuel handling system provides the means to receive, unload, store, and convey the delayed petroleum coke to the storage facility.

Crushed petroleum coke (size 2X0) is transferred from the refinery or barge to the coke storage dome by transfer belt conveyors from the battery limit. Flux is delivered by truck at truck unloading hopper and conveyed to the flux storage silo by pneumatic conveyor. Petroleum coke and flux are mixed by the weigh belt feeders and transferred by coke feed conveyors to the day storage bins above the rod mills in the slurry preparation area (area 150).

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur removal. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

The petroleum coke slurry feed for the gasification plant is produced by wet grinding in a pair of 60% capacity rod mills. In order to produce the desired slurry solids concentration, coke is fed to each rod mill with water that is recycled from other areas of the gasification plant. Prepared slurry is stored in agitated tanks.

All tanks, drums and other areas of potential atmosphere exposure of the product slurry or recycled water are covered and vented into the tank vent collection system for vapor emission control.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-GAS^{TM} Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a horizontal refractory lined vessel into which oxygen and coke and flux slurry are atomized via opposing mixer nozzles. The coke and flux slurry, recycle solids, and oxygen are fed sub-stoichiometrically at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coke is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the coke is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are easily removed by downstream processing.

Mineral matter in the coke and flux form a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows up from the horizontal section into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which additional coke slurry is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This additional coke feed serves to lower the temperature of the gas exiting the first stage by the endothermic nature of the equilibrium reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by additional slurry injection (slurry quench) instead of syngas recycle which is used at Wabash River. No oxygen is introduced into the second stage.

The gas and entrained particulate matter exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

The raw gas leaving the high temperature heat recovery unit passes through a hybrid dry cyclone/wet scrubber particulate removal system to remove solids and water soluble impurities from the syngas. The recovered particulates are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir in the top of the bin and goes to a settler in which the remaining slag fines are settled. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, and a water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

The scrubbed syngas is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the downstream Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the desired high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a single train with backup sour water feed storage.

A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam-stripping at a lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiency.

A.3.4.5 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

Two 50% capacity ASUs are provided to deliver the required oxygen for the coke gasification process. Each ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous production.

A.3.6 Power Block

The major components of the power block include two gas turbine generators (GTG), two heat recovery steam generators (HRSG), a steam turbine generator (STG), and numerous supporting facilities.

A.3.6.1 AREA 500 - Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and stack

Each of the two combustion turbine generators are General Electric 7FA+e, nominal 210 MW output each. Each GTG utilizes moisturized syngas and steam injection for NO_x control. Combustion exhaust gases are routed from each GTG to its associated HRSG and stack. Natural gas is used as back-up fuel for the gas turbine during startup, shutdown, and short duration transients in syngas supply.

The HRSG receives the combustion turbine exhaust gases and generates steam at the main steam and reheat steam energy levels. It generates high pressure (HP) steam and provides condensate heating for both the combined cycle and the gasification facilities.

The HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSG boiler includes a steam drum for proper steam purity and to reduce surge during cold start. Large unheated down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

Each stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 - Steam Turbine (ST)

The reheat, condensing turbine includes an integrated HP/IP opposed flow section and an axial flow LP section. Turbine exhaust steam is condensed in a surface condenser. The reheat design ensures high thermal efficiency and excellent reliability. It will produce 150 MW of electric power.

A.3.6.3 Power Delivery System

The power delivery system includes the combustion turbine generator output at 18 kilovolts (kV) with each connected through a generator breaker to its associated main power step-up transformer. A separate main step-up transformer and generator breaker is included for the ST generator. The HV switch yard receives the energy from the three generator step-up transformers at 230 kV.

Two auxiliary transformers are connected between the GTG breakers and the step-up transformers. Due to the large auxiliary load associated with the IGCC coproduction plant, internal power is distributed at 33 kV from the two auxiliary power transformers. The major motor loads in the ASU plants will be serviced by 33/13.8 kV transformers. The balance of the project loads will be served by several substations with 33/4.16 kV transformers supplying double ended electrical bus.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.7 Hydrogen Plant

A.3.7.1 AREA 450 – CO Shift Unit

Hydrogen production by the CO shift reaction is highly exothermic. High temperatures favor fast reaction rates, but result in unfavorable equilibrium conditions. Conversely, low temperatures favor the equilibrium conditions that allow the shift reaction to go to completion and result in low CO levels in the product gas. Also, the maximum allowable reactor outlet temperature must be below the catalyst sintering point and within the limits for practical vessel design. Thus, a two-stage reaction system is used with interstage cooling. The first high temperature shift reactor is designed to achieve high reaction rates at the highest allowable outlet temperature, and the second is designed to give a high conversion at a lower outlet temperature where the equilibrium conditions are more favorable. Approximately 93 percent of the carbon monoxide is converted to hydrogen in the first-stage reactor.

The clean syngas from the syngas moisturizer and preheater goes to the first CO shift reactor. Medium pressure steam is preheated and mixed with the syngas before it goes to the first-stage high temperature shift reactor. Adjusting the rate of steam addition controls the first-stage reactor outlet temperature.

The hot gas leaving the first-stage high temperature shift reactor is cooled by preheating the clean syngas and steam going to the first-stage reactor. It is further cooled before entering the second-stage shift reactor by the generation of medium pressure steam.

The hot gas leaving the second-stage shift reactor is cooled by steam generation producing medium pressure (420 psig) steam. It is further cooled by heating water for the syngas moisturizer, by preheating condensate, and then by a trim water cooler before going to the Pressure Swing Adsorption unit. Process condensate is separated in the knock-out drum and sent to condensate treatment.

Two 50% trains are needed as limited by maximum reactor vessel diameter to provide the required capacity and system reliability.

A.3.7.2 AREA 460 - Pressure Swing Adsorption Unit (PSA)

The shifted gas from the CO shift unit is sent to the pressure swing adsorbers for purification of the hydrogen product. Hydrogen recovery is 85%. The PSA system is based on the principle of pressure reduction and rapid cycle operation to remove impurities from the adsorbent. It consists of three major parts, i.e., adsorber vessels filled with adsorbent, a prefabricated valve skid, and a control panel containing the cycle control system.

A complete PSA cycle consists of four basic steps: adsorption, depressurization, purge at low pressure, and repressurization. Multiple adsorbent beds are used for high throughputs and hydrogen recovery.

Approximately 80 MMscfd of 99% hydrogen is produced and sent to the hydrogen compressors. The tail gas from the PSA is sent to the incinerator to produce high pressure steam for power generation.

A.3.7.3 AREA 470 - Hydrogen Compression

The hydrogen from the PSA unit is compressed to 1000 psig by the hydrogen compressors and delivered to the adjacent petroleum refinery.

<u>A.3.8 AREA 900 - Balance of Plant</u>

A.3.8.1 Cooling Water System

The design includes two cooling water systems. One provides the cooling duty for the power block. A separate system provides the cooling duty for the air separation unit and equipment cooling throughout the gasification facility.

The major components of the cooling water system consist of a cooling tower and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. Both cooling towers are multi-cell mechanically induced draft towers, sized to provide the design heat rejection at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.8.2 Fresh Water Supply

River water from an industrial water supply network is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.8.3 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, the hydrogen plant, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.8.4 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the refinery waste water system.

A.3.8.5 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The system consists of air compressors, air receivers, hose stations, and piping distribution for each unit. Additionally, the instrument air system consists of air dryers and a piping distribution system.

A.3.8.6 Incineration System

The tank vent stream is composed of primarily sweep gas and air purged through various in-process storage tanks that may contain small amounts of other gases such as ammonia and acid gas. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.8.7 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.8.8 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC power plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or fiber optics; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, and the coke handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical GT, ST, and generator, and ASU control parameters.

This approach retains control of IGCP equipment used to transport the coke, control turbines and generators, and to support the ASU. Other balance of plant equipment such as air compressors, condenser vacuum pumps, and water treatment use either local PLCs, or contact and relay control cabinets to operate the respective equipment. All remaining plant components are exclusively controlled by the DCS including the HRSG, the gasifier, ASU, hydrogen plant, electrical distribution, and other power block and gasification support systems.

A.3.8.9 Buildings

The plant has a central building housing the main control room, office, training, other administration areas and a warehouse/maintenance area. Other buildings are provided for water treatment equipment and the MCCs. The buildings, with the exception of water treatment, are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment.

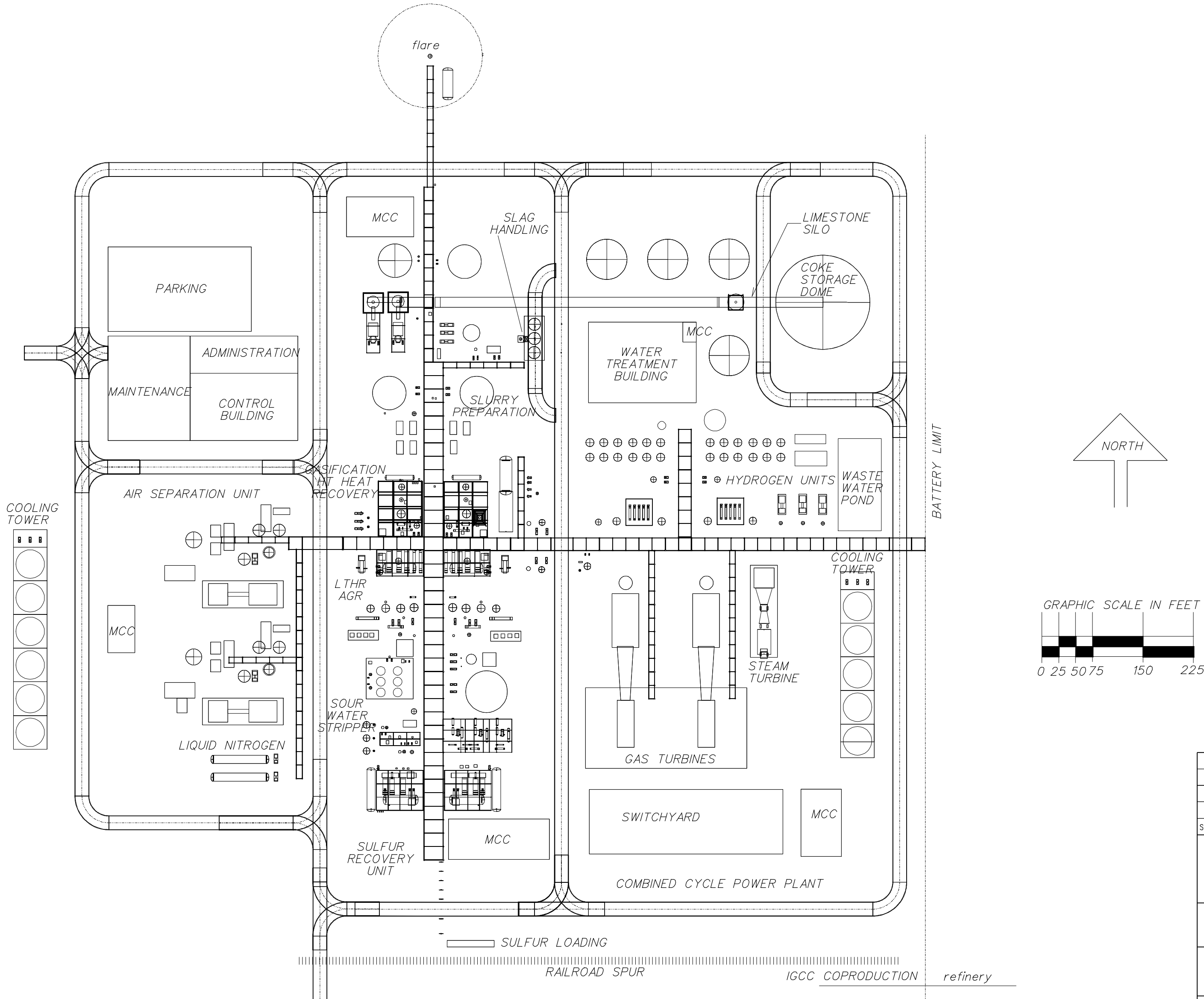
A.3.8.10 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the Optimized

Petroleum Coke IGCC Coproduction Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A	02/15/01	Modified	GMW				

SCALE: 1in = 75 ft. DESIGNED BY: G.M.Worthy DRAWN BY: G.M.Worthy

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

PET-COKE COPRODUCTION PLANT
SUBTASK 1.3

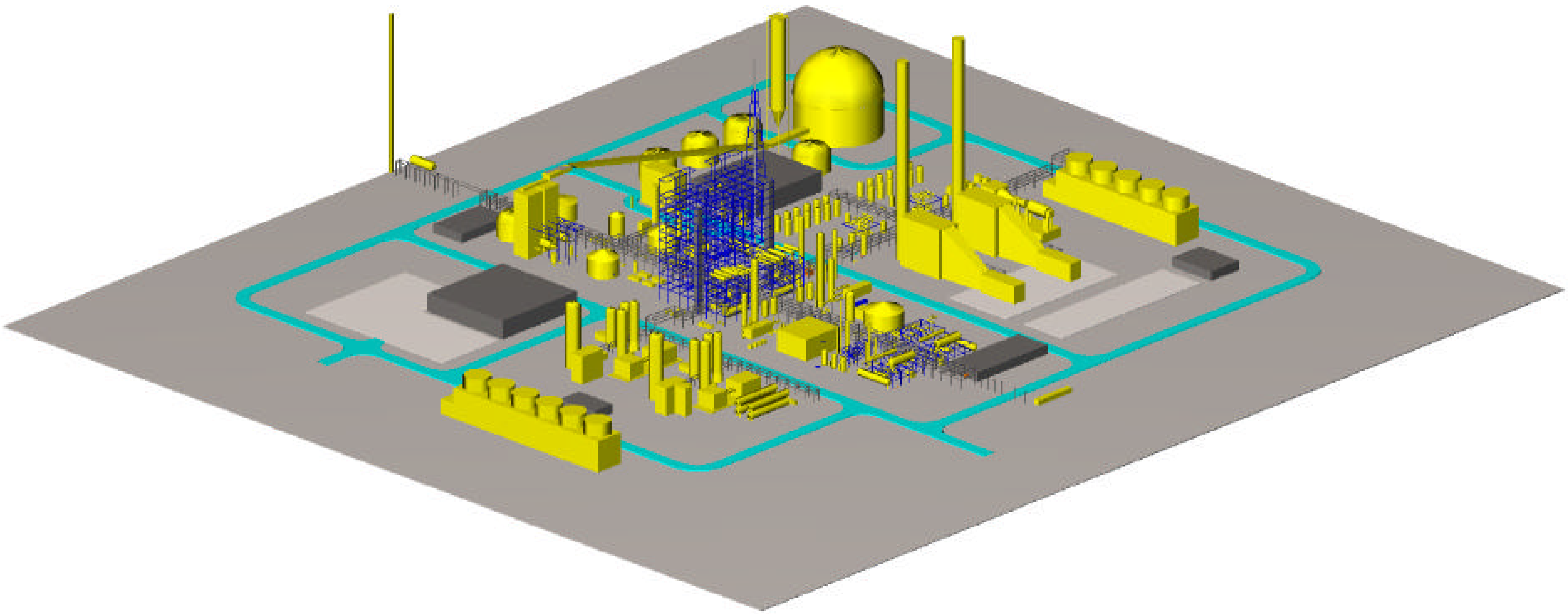
SITE PLAN

JOB No:	DRAWING No:	REV.
24355-104	SK - 00013	A

Figure A3

Artist's Conception of the Optimized

Petroleum Coke IGCC Coproduction Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, the Optimized Petroleum Coke IGCC Coproduction Plant Detailed Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 5,399 t/d of dry petroleum coke and produces 460.7 MWe of export electric power, 372 t/d of sulfur, 194.5 t/d of slag (containing 15 wt% water), and exports to the adjacent petroleum refinery 80 MMscfd of hydrogen and 980,000 lbs/hr of 700 psig/ 750^{o}F steam. It also consumes110.2 t/d of flux, 686,000 lbs/hr of condensate return from the refinery, and 5,194 gpm of river water.

Figure A5 shows the overall water flow diagram for the plant. This figure provides details of the water usage and losses within the plant. About 1,060 gpm of waste water is sent to the refinery outfall.

A.4.2 Performance Summary

Plant performance is based on the petroleum coke IGCC coproduction plant configuration including a GE 7FA+e gas turbine. Global Energy provided a heat and material balance for these facilities, using the design basis petroleum coke. This information was then integrated with a HRSG and reheat steam turbine. The GT Pro™ computer simulation program was used to simulate combined cycle performance and plant integration.[1]

Table A1 summarizes the overall performance of the Optimized Petroleum Coke IGCC Coproduction Plant. As shown in the table, the oxygen input to the gasifiers is 5,917 t/d, and the heat input is 6,680 MMBtu/hr. The two gas turbines produce 420 MW of power from their generators. The steam turbine produces another 150 MW of power for a total power generation of 570 MW. Internal power usage consumes 109.3 MW leaving a net power production of 460.7 MW for export.

Table A2 summarizes the expected emissions from the Optimized Petroleum Coke IGCC Coproduction Plant. The GE 7FA+e gas turbines and HRSG system has a stack exhaust flow rate of 7,967,000 lb/hr at 238^{o}F. On a dry basis adjusted to 15% oxygen, these gases have a SOx concentration of 3 ppmv, a NOx concentration of 10 ppmv, and a CO concentration of 10 ppmv. The incinerator stack has an exhaust flow rate of 635,300 lb/hr at 500^{o}F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 322 ppmv, a NOx concentration of 40 ppmv, and a CO concentration of 50 ppmv.

The plant emits 8,602,300 lbs/hr of total exhaust gases having an average SOx concentration of 24 ppmv, an average NOx concentration of 12 ppmv, and an average CO concentration of 13 ppmv. Expressed another way, this is 385 lb/hr of SOx (as SO_2), 166 lb/hr of NOx (as NO_2), and 105 lb/hr of CO. Compared to the non-optimized Petroleum

[1] GT Pro is a registered trademark of the Thermoflow Corporation.

Coke IGCC Coproduction Plant of Subtask 1.2, the SOx emissions are slightly higher reflecting the increased coke feed rate. The sulfur removal is 99.3%. The NOx emissions are about half and CO emissions are about 10% lower as a result of the improved performance of the GE 7FA+e gas turbine compared to the GE 7FA gas turbine which was used in Subtask 1.2. The CO_2 emissions are about 40% higher than those of Subtask 1.2 because this case does not send the low Btu PSA off gas to the adjacent petroleum refinery for fuel, but instead burns it to produce high pressure steam which is used in the steam turbines to produce power. In Subtask 1.2, the CO_2 emissions associated with the combustion of this low Btu gas would be attributed to the refinery rather than the Petroleum Coke IGCC Coproduction Plant.

Table A1

Performance Summary of the Optimized Petroleum Coke IGCC Coproduction Plant

Ambient Temperature, °F	70
Coke Feed, as received, TPD	5,673
Dry Coke Feed to Gasifiers, TPD	5,399
Total Fresh Water Consumption, gpm	5,150
Condensate Returned from the Refinery, gpm	1,372
Flux,TPD	110.2
Sulfur, TPD	371.8
Slag Produced, TPD (15% moisture)	194.5
HP Steam Export, lb/hr	980,000
Hydrogen Production, MMscfd	80
Fuel Gas Export, MMscfd	0
Total Oxygen Feed to the Gasifiers, TPD of 95% O_2	5,917
Heat Input to the Gasifiers (HHV), Btu/hr x 10^6	6,680
Cold Gas Efficiency at the Gas Turbine (HHV), %	77.4
Fuel Input to Gas Turbines, lb/hr	984,635
Heat Input to Gas Turbines (LHV), Btu/hr x 10^6	3,580
Steam Injection to Gas Turbines, lb/hr	429,120
Gas Turbines Output, MW	420
Steam Turbine Output, MW	150
Gross Power Output, MW	570
Gasification Plant Power Consumption, MW	(17.8)
ASU Power Consumption, MW	(70.6)
Balance of Plant & Auxiliary Load Power Consumption, MW	(15.6)
Hydrogen Plant & Compressors, MW	(5.4)
Net Power Output, MW	460.7

Table A2

**Environmental Emissions Summary*
of the Optimized Petroleum Coke
IGCC Coproduction Plant**

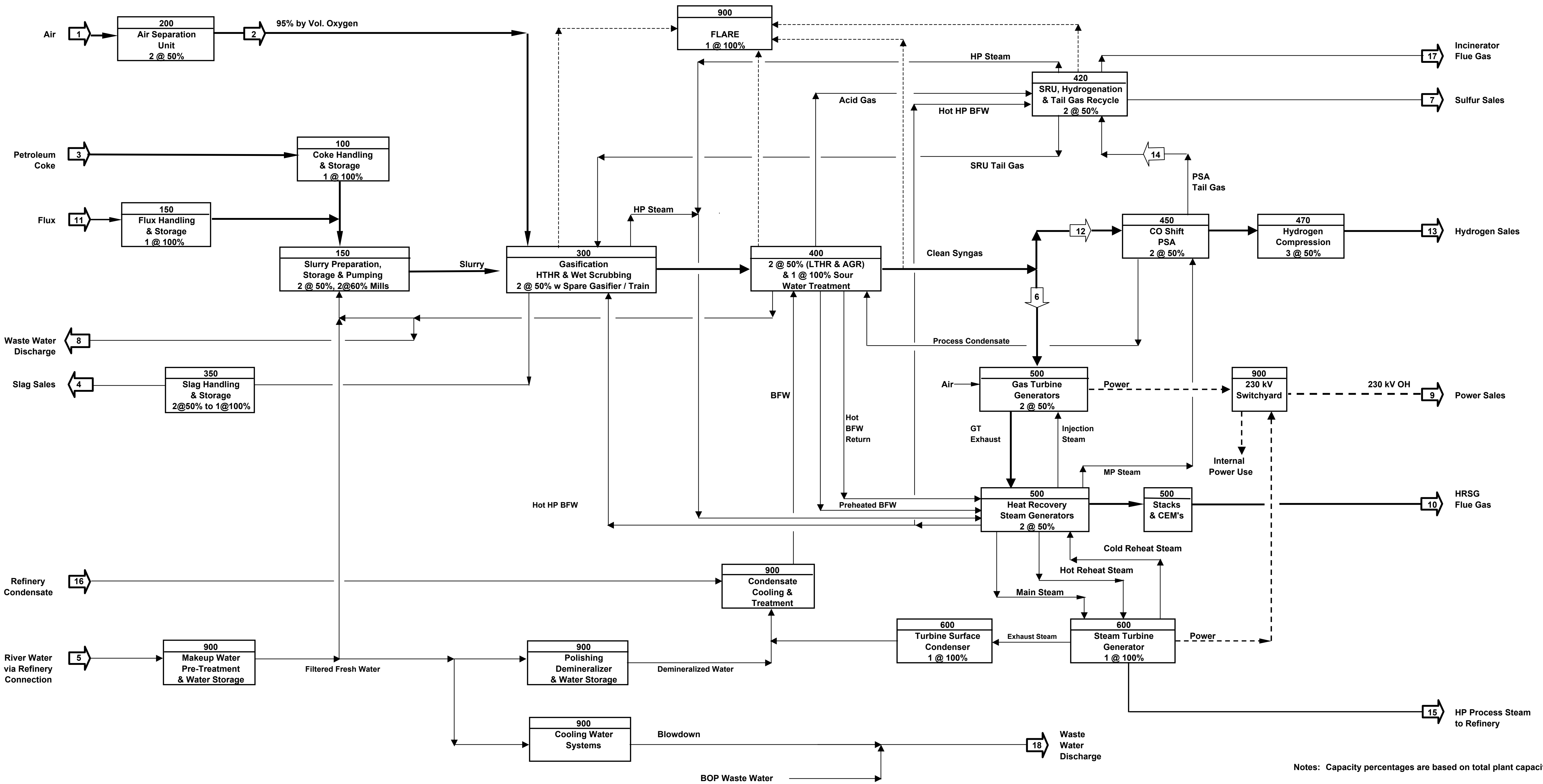
Total Gas Turbine Emissions	
GT/HRSG Stack Exhaust Flow Rate (from 2 trains), lb/hr	7,967,000
GT/HRSG Stack Exhaust Temperature, °F	238
Emissions (at 15% oxygen, dry basis)	
SO_x, ppmvd	3
SO_x as SO_2, lb/hr	49
NO_x, ppmvd	10
NO_x as NO_2, lb/hr	136
CO, ppmvd	10
CO, lbl/hr	79
Incinerator Emissions	
Stack Exhaust Flow Rate, lb/hr	635,300+
Stack Exhaust Temperature, °F	500
Emissions (at 3% oxygen, dry basis)	
SO_x, ppmvd	283
SO_x as SO_2, lb/hr	336
NO_x, ppmvd	40
NO_x as NO_2, lb/hr	29
CO, ppmvd	50
CO, lbl/hr	26
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	8,602,300+
Emissions	
SO_x, ppmvd	24
SO_x as SO_2, lb/hr	385
NO_x, ppmvd	14
NO_x as NO_2, lb/hr	166
CO, ppmvd	15
CO, lbl/hr	105
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	99.4

* Expected emissions performance
\+ Includes PSA tail gas

Figure A4

Detailed Block Flow Diagram of the Optimized

Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coke	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	Flux	Syngas	Hydrogen	Tail Gas	HP Steam	Condensate	Flue Gas	Waste			
Flow	25,800	5,917	5,399	194.5	2,597,000	984,635	371.8	27,440	460,700	7,966,800	110.2	355,030	80	90.7	980,000	686,000	635,300	501,500			
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Tons/Day	Lb/Hr	MMSCFD	MMSCFD	Lb/Hr	Lb/Hr	Lb/Hr	Lb/Hr			
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	NA	350	1,000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	Ambient	180	70	530	332	80	NA	238	NA	530	120	115	750	190	500	71			
HHV Btu/lb	NA	NA	14848	NA	NA	3,848	NA	NA	NA	NA	NA	3,848	NA	782	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	NA	NA	NA	3,646	NA	NA	NA	NA	NA	3,646	NA	779	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,680	NA	NA	3,789	NA	NA	NA	NA	NA	1,366	1,083	282	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	Not Calc.	NA	NA	3,590	NA	NA	NA	NA	NA	1,294	917	281	NA	NA	NA	NA			
Notes	Dry Basis	5580 O2	Dry Basis	15%Wtr.	5,194 GPM	To GT	Sales	55 GPM	230 kV			For H2	Sales	360 MLb/hr	Sales	Return		1,003 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.3

OPTIMIZED PETROLEUM COKE IGCC

COPRODUCTION PLANT

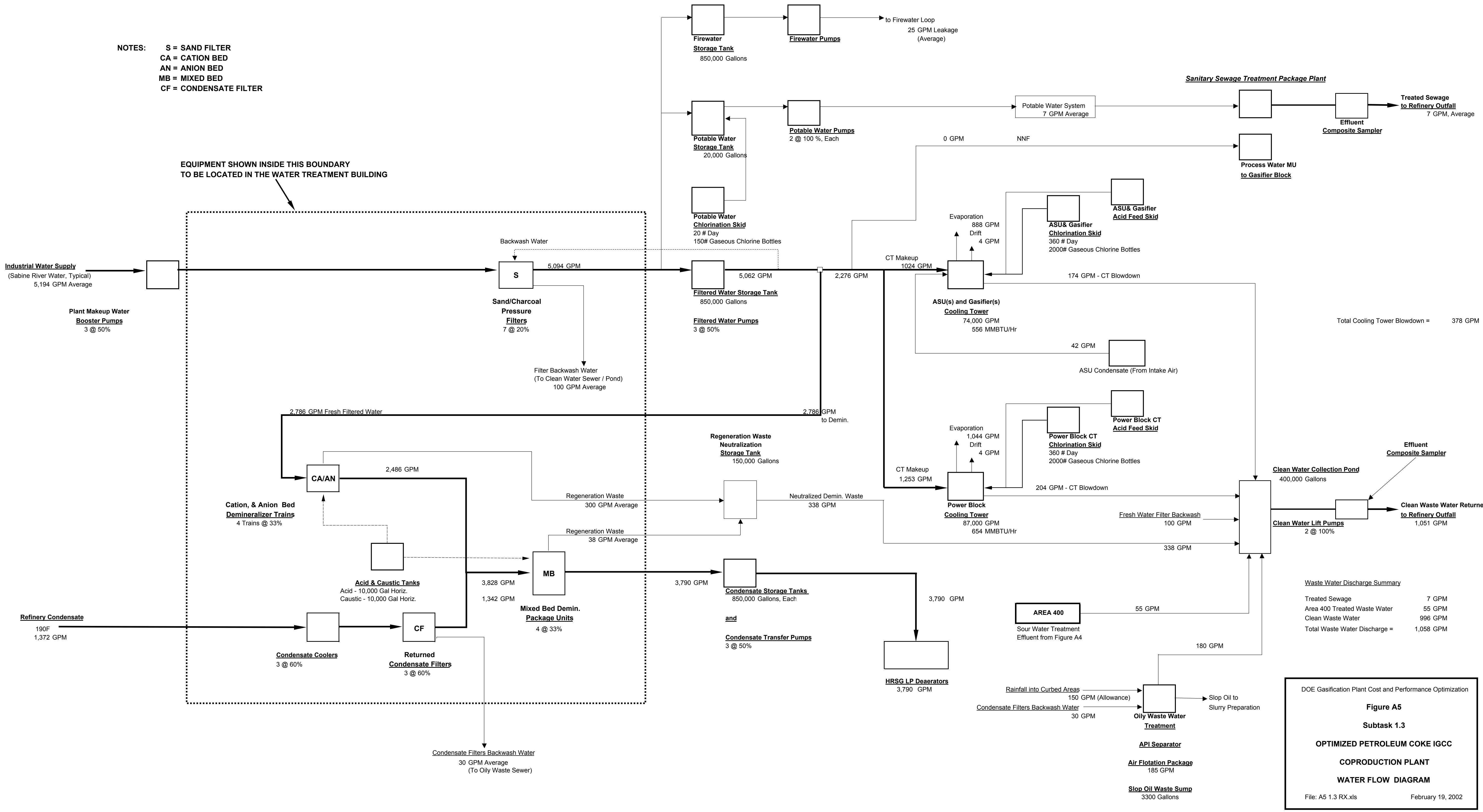
BLOCK FLOW DIAGRAM

File: Fig A4 1.3 R1.xls February 21, 2002

Figure A5

Overall Water Flow Diagram of the Optimized

Petroleum Coke IGCC Coproduction Plant



NOTES: S = SAND FILTER
CA = CATION BED
AN = ANION BED
MB = MIXED BED
CF = CONDENSATE FILTER
EQUIPMENT SHOWN INSIDE THIS BOUNDARY
TO BE LOCATED IN THE WATER TREATMENT BUILDING
Industrial Water Supply
(Sabine River Water, Typical)
5,194 GPM Average
Plant Makeup Water
Booster Pumps
3 @ 50%
Backwash Water
S
5,094 GPM
Sand/Charcoal
Pressure
Filters
7 @ 20%
Filter Backwash Water
(To Clean Water Sewer / Pond)
100 GPM Average
Firewater
Storage Tank
850,000 Gallons
Firewater Pumps
to Firewater Loop
25 GPM Leakage
(Average)
Potable Water
Storage Tank
20,000 Gallons
Potable Water Pumps
2 @ 100 %, Each
Potable Water System
7 GPM Average
Potable Water
Chlorination Skid
20 # Day
150# Gaseous Chlorine Bottles
Filtered Water Storage Tank
850,000 Gallons
5,062 GPM
Filtered Water Pumps
3 @ 50%
2,276 GPM
Sanitary Sewage Treatment Package Plant
Effluent
Composite Sampler
Treated Sewage
to Refinery Outfall
7 GPM, Average
0 GPM
NNF
Process Water MU
to Gasifier Block
Evaporation
888 GPM
Drift
4 GPM
CT Makeup
1024 GPM
ASU& Gasifier
Chlorination Skid
360 # Day
2000# Gaseous Chlorine Bottles
ASU& Gasifier
Acid Feed Skid
174 GPM - CT Blowdown
ASU(s) and Gasifier(s)
Cooling Tower
74,000 GPM
556 MMBTU/Hr
Total Cooling Tower Blowdown = 378 GPM
42 GPM
ASU Condensate (From Intake Air)
2,786 GPM Fresh Filtered Water
2,786 GPM
to Demin.
Evaporation
1,044 GPM
Drift
4 GPM
Power Block CT
Chlorination Skid
360 # Day
2000# Gaseous Chlorine Bottles
Power Block CT
Acid Feed Skid
CT Makeup
1,253 GPM
204 GPM - CT Blowdown
Power Block
Cooling Tower
87,000 GPM
654 MMBTU/Hr
Regeneration Waste
Neutralization
Storage Tank
150,000 Gallons
CA/AN
2,486 GPM
Cation, & Anion Bed
Demineralizer Trains
4 Trains @ 33%
Regeneration Waste
300 GPM Average
Neutralized Demin. Waste
338 GPM
Regeneration Waste
38 GPM Average
Acid & Caustic Tanks
Acid - 10,000 Gal Horiz.
Caustic - 10,000 Gal Horiz.
MB
3,828 GPM
1,342 GPM
Mixed Bed Demin.
Package Units
4 @ 33%
3,790 GPM
Condensate Storage Tanks
850,000 Gallons, Each
and
Condensate Transfer Pumps
3 @ 50%
3,790 GPM
HRSG LP Deaerators
3,790 GPM
Refinery Condensate
190F
1,372 GPM
Condensate Coolers
3 @ 60%
CF
Returned
Condensate Filters
3 @ 60%
Condensate Filters Backwash Water
30 GPM Average
(To Oily Waste Sewer)
Clean Water Collection Pond
400,000 Gallons
Effluent
Composite Sampler
Fresh Water Filter Backwash
100 GPM
338 GPM
Clean Water Lift Pumps
2 @ 100%
Clean Waste Water Returned
to Refinery Outfall
1,051 GPM
AREA 400
55 GPM
Sour Water Treatment
Effluent from Figure A4
Waste Water Discharge Summary
Treated Sewage 7 GPM
Area 400 Treated Waste Water 55 GPM
Clean Waste Water 996 GPM
Total Waste Water Discharge = 1,058 GPM
180 GPM
Rainfall into Curbed Areas
150 GPM (Allowance)
Condensate Filters Backwash Water
30 GPM
Oily Waste Water
Treatment
Slop Oil to
Slurry Preparation
API Separator
Air Flotation Package
185 GPM
Slop Oil Waste Sump
3300 Gallons
DOE Gasification Plant Cost and Performance Optimization
Figure A5
Subtask 1.3
OPTIMIZED PETROLEUM COKE IGCC
COPRODUCTION PLANT
WATER FLOW DIAGRAM
File: A5 1.3 RX.xls
February 19, 2002

A.5 Major Equipment List

Table D3 lists the major pieces of equipment and systems by process area in the Optimized Petroleum Coke IGCC Coproduction Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit and the PSA unit, are not available.

Table A3
Major Equipment of the Optimized Petroleum Coke IGCC Coproduction Plant

Fuel Handling – 100
Coke Storage Dome
Reclaim Conveyors
Storage/Feed Bins
Coke Handling Electrical Equipment and Distribution
Electric Hoist
Metal Detector
Magnetic Separator
Flux Silo
Vibrating Feeder
Slurry Preparation – 150
Weigh Belt Feeder
Rod Charger
Rod Mill
Rod Mill Product Tank
Rod Mill Product Tank Agitator
Rod Mill Product Pumps
Recycle Water Storage Tank
Recycle Water Pumps
Slurry Storage Tank
Slurry Storage Tank Agitator
Slurry Recirculation Pumps
Solids Recycle Tank
Solids Recycle Tank Agitator
Solids Recycle Pumps
Rod Mill Lube Oil Pumps
Slurry Feed Pumps (1st Stage)
Slurry Feed Pumps (2nd Stage)
ASU – 200
Air Separation Unit Including:
Main Air Compressor
Air Scrubber
Oxygen Compressor
Cold Box (Main Exchanger)
Oxygen Compressor Expander
Liquid Nitrogen Storage

ASU & Gasifier Area Cooling Water - 250
Cooling Water Circulation Pump
Cooling Tower (S/C)
Gasification - 300
Main Slurry Mixers
Second Stage Mixer
Gasifier Vessel
High Temperature Heat Recovery Unit (HTRU)
Cyclone Separators
Slag Pre-Crushers
Slag Crushers
Reactor Nozzle Cooling Pumps
Crusher Seal Water Pumps
Syngas Desuperheater
Nitrogen Heater
Pressure Reduction Units
Syngas Venturi Scrubber
Syngas Scrubber Column
Syngas Scrubber Roughing Filter
Syngas Scrubber Final Filter
Syngas Scrubber Recycle Pumps
Slag Handling – 350
Slag Dewatering Bins
Slag Gravity Settler
Slag Water Tank
Slag Water Pumps
Gravity Settler Bottoms Pumps
Slag Recycle Water Tank
Slag Feedwater Quench Pumps
Slag Water Recirculation Pumps
Polymer Pumps
Slag Recycle Water Cooler
LTHR/AGR – 400
Syngas Recycle Compressor
Syngas Recycle Compressor K. O. Drum
Syngas Heater
COS Hydrolysis Unit
Amine Reboiler
Sour Water Condenser
Sour Gas Condensate Condenser
Sour Gas CTW Condenser
Sour Water Level Control Drum
Sour Water Receiver
Sour Gas Knock Out Pot
Sour Water Carbon Filter
MDEA Storage Tank
Lean Amine Pumps
Acid Gas Absorber

MDEA Cross-Exchangers
MDEA CTW Coolers
MDEA Carbon Bed
MDEA Post-Filter
Acid Gas Stripper
Acid Gas Stripper Recirculation Cooler
Acid Gas Stripper Reflux Drum
Acid Gas Stripper Quench Pumps
Acid Gas Stripper Reboiler
Acid Gas Stripper Overhead Filter
Lean MDEA Transfer Pumps
Acid Gas Stripper Knock Out Drum
Acid Gas Stripper Preheater
Amine Reclaim Unit
Condensate Degassing Column
Degassing Column Bottoms Cooler
Sour Water Transfer Pumps
Ammonia Stripper
Ammonia Stripper Bottoms Cooler
Stripped Water Transfer Pumps
Quench Column
Quench Column Bottoms Cooler
Stripped Water Transfer Pumps
Degassing Column Reboiler
Ammonia Stripper Reboiler
Syngas Heater
Syngas Moisturizer
Moisturizer Recirculation Pumps
Sulfur Recovery – 420
Reaction Furnace/Waste Heat Boiler
Condensate Flash Drum
Sulfur Storage Tank
Storage Tank Heaters
Sulfur Pump
Claus First Stage Reactor
Claus First Stage Heater
Claus First Stage Condenser
Claus Second Stage Reactor
Claus Second Stage Heater
Claus Second Stage Condenser
Condensate Level Drum
Hydrogenation Gas Heater
Hydrogenation Reactor
Quench Column
Quench Column Pumps
Quench Column Cooler
Quench Strainer
Quench Filter
Tail Gas Recycle Compressor

Tail Gas Recycle Compressor Intercooler
Tank Vent Blower
Tank Vent Combustion Air Blower
Tank Vent Incinerator/Waste Heat Boiler
Tank Vent Incinerator Stack
CO Shift – 450
ZnO Reactor
HT Shift Reactor
LT Shift Reactor
Gas-gas Exchanger
Steam Generator
Air Cooler
Start-up Fired Heater
PSA – 460
PSA Unit
Hydrogen Compression – 470
Hydrogen Compressors
Gas Turbine / HRSG – 500
Gas Turbine Generator (GTG), GE 7FA+e Dual Fuel (Gas and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.
GTG Erection (S/C)
Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, with Integral Deaerator
HRSG Stack (S/C)
HRSG Continuous Emissions Monitoring Equipment
HRSG Feedwater Pumps
HRSG Blowdown Flash Tank
HRSG Atmospheric Flash Tank
HRSG Oxygen Scavenger Chemicals Injection Skid
HRSG pH Control Chemicals Injection Skid
GTG Iso-phase Bus Duct
GTG Synch Breaker
Power Block Auxilary Power XformerS
Steam Turbine Generator & Auxiliaries - 600
Steam Turbine Generator (STG), Reheat, TC2F, Complete with Lube Oil Console
Steam Surface Condenser, 316L tubes
Condensate (hotwell) pumps
Circulating Water Pumps
Auxiliary Cooling Water Pumps
Cooling Tower
Balance Of Plant - 900
High Voltage Electrical Switch Yard (S/C)
Common Onsite Electrical and I/C Distribution
Distributed Control System (DCS)
In-Plant Communication System

15KV, 5KV and 600V Switchgear
BOP Electrical Devices
Power Transformers
Motor Control Centers
Makeup Pumps
Substation & Motor Control Center (MCC)
Lighting, Heating & Ventilation
Makeup Water Treatment Storage and Distribution
Water Treatment Building Equipment
Carbon Filters
Cation Demineralizer Skids
Degasifiers
Anion Demineralizer Skids
Demineralizer Polishing Bed Skids
Bulk Acid Tank
Acid Transfer Pumps
Demineralizer - Acid Day Tank Skid
Bulk Caustic Tank Skid
Caustic Transfer Pumps
Demineralizer - Caustic Day Tank Skid
Firewater Pump Skids
Waste Water Collection and Treatment
Oily Waste - API Separator
Oily Waste - Dissolved Air Flotation
Oily Waste Storage Tank
Sanitary Sewage Treatment Plant
Wastewater Storage Tanks
Monitoring Equipment
Common Mechanical Systems
Shop Fabricated Tanks
Miscellaneous Horizontal Pumps
Auxiliary Boiler
Safety Shower System
Flare
Flare Knock Out Drum
Flare Knock Out Drum Pumps
Chemical Feed Pumps
Chemical Storage Tanks
Chemical Storage Equipment
Laboratory Equipment

The petroleum coke IGCC plant is assumed to be located adjacent to a petroleum refinery, and thus, can share some infrastructure with the refinery. It is assumed that

1. The refinery delivers the coke to the coke storage dome.
2. The IGCC plant gets the river water from the refinery water intake system.
3. The refinery processes the process waste water from the IGCC plant through the refinery waste water treatment facilities.

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.3 scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 42 months which includes three months of performance testing before full commercial operation. Notice to proceed is based on a confirmed Gulf Coast plant site and availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor and air separation unit.

The project construction schedule of the Optimized Petroleum Coke IGCC Coproduction Plant was developed by examining that of the Wabash River Repowering Project and correcting for several problems that were encountered during construction. Furthermore, construction experts were included in the Value Improving Practices team that developed the plant layout so that both ease of construction and maintenance were considered.

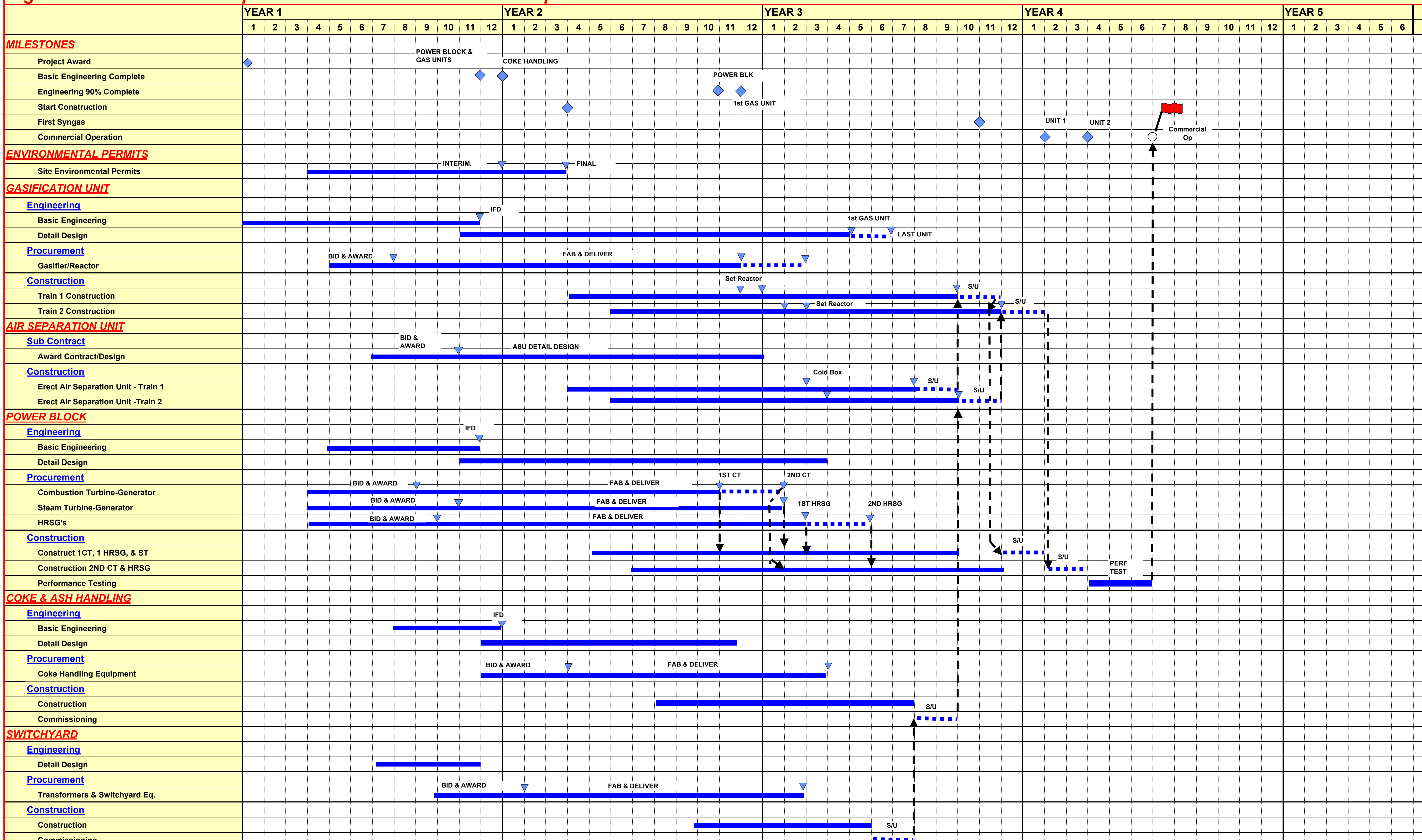
The milestone construction schedule for the major process blocks of the Optimized Petroleum Coke IGCC Coproduction Plant is shown in Figure A6.

Figure A6

Milestone Construction Schedule for the

Optimized Petroleum Coke IGCC Coproduction Plant

Figure A6 - Subtask 1.3 - Optimized Petroleum Coke IGCC Coproduction Plant



BY	DATE	REV.
NS	9/7/01	E
TM	3/26/01	D
TM	9/11/00	C
SO	6/28/00	B
RHS	6/23/00	A

Bechtel
Houston, Texas

US DEPARTMENT OF ENERGY
Gasification Plant Cost & Performance Optimization
Subtask 1.3 Optimized Petcoke IGCC
Milestone Schedule

A.6.2 Capital Cost Summary

A.6.2.1. General

The following table illustrates the work breakdown structure (WBS) for Subtask 1.3 and the source of the cost information for each of the areas. The WBS for Subtask 1.3 is the same as that which was used for Subtask 1.2.

WBS	Description	Subtask 1.3
100	Solid Fuel Handling	Bechtel Engineering to provide scope and estimate
150	Slurry Preparation	Adjusted Wabash River and selected quotes
200	Air Separation Unit	Praxair Quote
300	Gasification	Adjusted Wabash River and selected quotes
350	Slag Handling	Adjusted Wabash River
400	Sulfur Removal	Adjusted Wabash River and selected quotes
420	Sulfur Recovery	Adjusted Wabash River and selected quotes
450	CO Shift	Bechtel Engineering to provide scope and estimate
460	PSA	Bechtel Engineering to provide scope and UOP quote
470	Hydrogen Compression	Bechtel Engineering to provide scope and compressor quotes
500	GT/HRSG	Based on Bechtel's Powerline™ design and cost information
600	Steam Turbine & Auxiliary Equipment	Based on Bechtel's Powerline™ design and cost information
900	Balance Of Plant	
	High Voltage Switchyard	Bechtel Engineering to provide scope and estimate
	Makeup Water Intake	Bechtel Engineering to provide scope and estimate
	Makeup Water Treatment System	Bechtel Engineering to provide scope and estimate
	Waste Water Collection System	Bechtel Engineering to provide scope and estimate
	Waste Water Discharge	Discharged to refinery discharge system
	Solids Discharge	Used catalyst to landfill
	Piping	By Comet model as calibrated to Wabash River
	Concrete, Steel and Architecture	Wabash River / PSI adjusted for technical basis
	Common Electrical and I&C Systems	Based on Wabash River adjusted for technical basis

Vendor quotes were obtained for most of the new and high price equipment in Subtask 1.3. The power block cost estimate is based on an estimated current General Electric price for the 7FA+e gas turbines and Bechtel Powerline™ cost for similar sized power plant currently under construction on the Gulf Coast. Thus, compared to Subtask 1.2, a much smaller part of the plant costs were estimated based on the Wabash River facility and adjusted for inflation. Gulf Coast non-union mid-year 2000 labor rates were used, the same labor rate as was used for Subtask 1.2 so that this cost estimate is comparable. Union Labor rates were used for Subtask 1.1.

This cost estimate is an instantaneous mid-year 2000 cost estimate based on market pricing. There is no forward escalation. As such, it reflects any aberrations in equipment costs based on current market conditions. For example, there is a large demand and backlog for gas turbines so that the current price seems high based on historical data.

Major Equipment

Major equipment from Subtasks 1.1 and 1.2 was loaded into a data base and modified to reflect the scope of Subtask 1.3. Modifications include changes in equipment duty (as a result of both capacity changes and the Design-to-Capacity VIP), quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

The Design-to-Capacity and Classes of Plant Quality Value Improving Practices were considered in sizing the equipment for the Subtask 1.3 plant. Because the composition of delayed petroleum coke is less variable than the range of coals that were considered in the design of the Wabash River Repowering Project, less overdesign was needed in many areas to provide feedstock flexibility. Furthermore, some equipment was redesigned to reflect current engineering design practices.

Bulk Materials

Wabash River Repowering Project bulk commodity quantity estimates for steel, concrete, and piping were used as the basis, and then the quantities were adjusted to reflect the scope and site plan for this subtask. Current pricing was used to estimate the costs for the bulk material items.

Subcontracts

Supply and install subcontract pricing was estimated for:

By Budget Quote
- Coke Handling
- Field Erected Tanks
- Air Separation Unit
- Cooling Tower (except basin)

By Unit Pricing
- Buildings including interior finish, HVAC, and Furnishings
- Fire Protection Systems
- Site Development
- Rail Spur

From the Wabash River Facility
- Painting and Insulation
- 230 KV Switchyead
- Gasifier Refractory
- Start-up Services; i.e., flushes and steam blows

Construction

Labor is based on mid-year 2000 Gulf Coast merit shop rates and historic productivity factors. Union labor is used for refractory installation.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.3. Power block costs are based on Bechtel's Powerline^{TM} design and current cost information.

Material Take-off

Subtask 1.1 quantities were used as the basis and adjusted to reflect the scope and site plan for Subtask 1.3, as was done for Subtask 1.2. Modifications were made, as necessary. Concrete, steel and instrumentation were adjusted on an area by area basis reflecting the increased numbers of process trains. The basis for piping adjustment was developed from quantities generated by the COMET model. Electrical quantities were manually adjusted for this subtask.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Design criteria basis are the codes, standards, laws and regulations to be compliant with U. S. and local codes for the designated region typical for U. S. installations and for the designated location of the plant.
- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000 Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- For new and highly priced equipment, current vendor quotes were obtained to reflect current market pricing.
- Site Conditions:
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Tie-ins to the adjoining refinery are located on the north and east sides of the site
  - Coke is provided at the battery limits on the north side of the site
- Cost includes only areas within the site plan
- Critical spares are included; e.g., proprietary items, one-of-a-kind items, and long lead time items. Normal warehouse, operational, and commissioning/start-up spares are excluded.
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)

- The following costs are excluded:
  - Contingency and risks
  - Cost of permits
  - Taxes
  - Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
  - Facilities external to the site in support of the plant
  - Licensing fees
  - Agent fees
  - Initial fill of chemicals

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Optimized Petroleum Coke IGCC Coproduction Plant.

Table A4

Capital Cost Summary of the Optimized Petroleum Coke IGCC Coproduction Plant

Plant Area	Direct Field Material			
Solids Handling	4,300,000	2,700,000	1,012,000	8,012,000
Air Separation Unit	65,058,000	40,973,000	826,000	106,857,000
Gasification	179,878,000	71,026,000	47,064,000	297,968,000
Hydrogen Production	31,939,000	4,919,000	6,073,000	42,931,000
Power Block	193,711,000	22,085,000	14,425,000	230,221,000
Balance Of Plant	47,202,000	27,407,000	3,441,000	78,050,000
Total	522,088,000	169,110,000	72,842,000	764,040,000

Note: Because of rounding, some columns may not add to the total that is shown.

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±10%. The level of accuracy reflects a high degree of confidence based on the large number of vendor quotes that were obtained and that the power block costs are based on a current similar Gulf Coast power project. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

Appendix C

Subtask 1.3 (Appendix B)

Spare Solids Handling Petroleum Coke IGCC Coproduction Plant

Appendix C
Subtask 1.3 (Appendix B)

Spare Solids Handling Petroleum Coke IGCC Coproduction Plant

The Subtask 1.3 Spare Solids Handling Petroleum Coke IGCC Coproduction Plant is similar to the Subtask 1.3 Minimum Cost Petroleum Coke IGCC Coproduction Plant except that it has three parallel syngas generation trains, instead of two. That is there are three trains from the slurry feed pumps through the particulate removal system. Specifically, there are three parallel slurry feed, gasification, high temperature heat removal, and dry and wet particulate removal trains feeding the downstream section of the plant which consists of only two parallel trains. The downstream section of the plant is sized so that it can only process the full output from two syngas generation trains. Thus, one the three syngas generation trains is kept in reserve to replace an operating train when it has an outage and needs maintenance. Once the maintenance work is complete, the train that was taken off line now is the spare train.

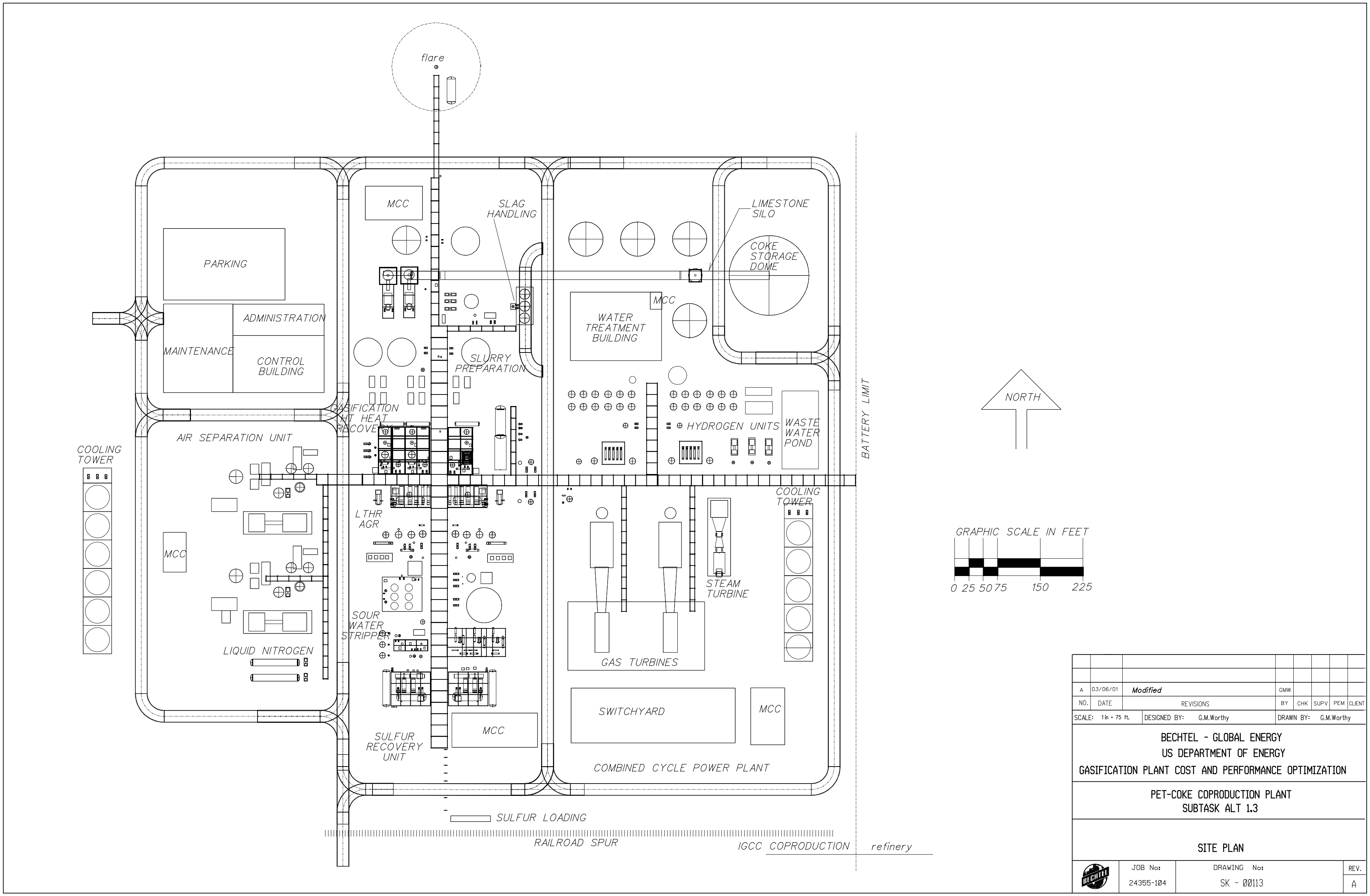
Each of the three parallel gasification trains is identical, and they are the same as each of the gasification trains in the minimum cost case since they contain only a single gasifier vessel. In the Subtask 1.3 Base Case, each gasification train contains a spare gasification vessel that can be worked on when the other one is in service.

Because of the presence of the third gasification train in the Spare Solids Handling Case, the site plan for this case is somewhat larger than that of the Subtask 1.3 Base Case. Figure B1 contains the site plan for the Spare Solids Handling Case. The additional train in the Spare Solids Handling Case increases the width (east-west direction) of the plant by 25 feet. There is no change in the other dimension of the plant. The net result is that the plant site increases by 1 acre to 52 acres.

Figure B1

Site Plan of the Subtask 1.3 Spare Solids Handling

Optimized Petroleum Coke IGCC Coproduction Plant


flare
MCC
SLAG HANDLING
LIMESTONE SILO
COKE STORAGE DOME
PARKING
ADMINISTRATION
MAINTENANCE
CONTROL BUILDING
WATER TREATMENT BUILDING
MCC
SLURRY PREPARATION
GASIFICATION HT HEAT RECOVERY
HYDROGEN UNITS
WASTE WATER POND
BATTERY LIMIT
NORTH
COOLING TOWER
AIR SEPARATION UNIT
MCC
LTHR AGR
COOLING TOWER
GRAPHIC SCALE IN FEET
0 25 50 75 150 225
STEAM TURBINE
SOUR WATER STRIPPER
LIQUID NITROGEN
GAS TURBINES
SWITCHYARD
MCC
MCC
SULFUR RECOVERY UNIT
COMBINED CYCLE POWER PLANT
SULFUR LOADING
RAILROAD SPUR
IGCC COPRODUCTION
refinery
A 03/06/01 Modified GMW
NO. DATE REVISIONS BY CHK SUPV PEM CLIENT
SCALE: 1in = 75 ft. DESIGNED BY: G.M.Worthy DRAWN BY: G.M.Worthy
BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION
PET-COKE COPRODUCTION PLANT
SUBTASK ALT 1.3
SITE PLAN
JOB No: 24355-104
DRAWING No: SK - 00113
REV. A

Appendix C

Subtask 1.3 (Appendix C)

Financial Model Analysis Input

Appendix C

Financial Analysis Model Input

Bechtel Technology and Consulting (now Nexant) developed the DCF financial model as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task.[1] This model performs a discounted cash flow financial analysis to calculate investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data directly related to the specific plant as follows.

<u>Data on the Plant Input Sheet</u>

- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table C1 contains the data that are entered on the Plant Input Sheet for Subtask 1.2 and for the three Subtask 1.3 cases.

The Scenario Input Sheet primarily contains data that are related to the general economic environment that is associated with the plant. In addition, it also contains some data that are plant related. The data on the Scenario Input Sheet are shown below.

<u>Data on the Scenario Input Sheet</u>

- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Start up information

Table C2 contains the base case data that are entered on the Scenario Input Sheet for Subtask 1.2 and for the three Subtask 1.3 cases.

[1] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Table C1
Plant Input Sheet Data for Subtasks 1.2 and 1.3

Project Name / Description	Subtask 1.2 on 1.3 Basis	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Case
Project Location	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast
Project Type/Structure	BOO	BOO	BOO	BOO
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs	Multiple Outputs	Multiple Outputs	Multiple Outputs
Fuel Type (**Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Petroleum Coke	Petroleum Coke	Petroleum Coke	Petroleum Coke
Plant Input/Output Flowrates - Daily Average Basis (Calendar Day)				
Syngas Capacity (MMscf/day) - Optional				
Gross Electric Power Capacity (MW) - Optional	487	570	570	570
Net Electric Power Capacity (MW)	374.3	430.0	425.4	436.4
Steam Capacity (Tons/hr)	486.1	479.3	473.1	487.0
Hydrogen Capacity (MMscf/day)	78.8	77.5	76.5	78.7
Carbon Monoxide Capacity (MMscf/day) - PSA Tail Gas (Low Btu Fuel Gas)	99.8	0.0	0.0	0.0
Elemental Sulfur (Tons/day)	324.1	296.8	273.6	331.5
Slag Ash (Tons/day)	167.8	155.3	143.1	173.4
Fuel (Tons/day)	4,635.3	4,309.8	3,973.1	4,814.2
Chemicals - **Natural Gas (Mscf/day) - INPUT**	-10,099	-20,000	-26,977	-9,303
Environmental Credit (Tons/day)	0	0	0	0
Other (Tons/day) - Flux **- INPUT**	-94.5	-88.0	-81.1	-98.8
Operating Hours per Year	8,760	8,760	8,760	8,760
Guaranteed Availability (percentage)	100.0%	100.0%	100.0%	100.0%
Enter One of the Following Items Depending on Project Type:				
Heat Rate (Btu/kWh) based on HHV - Required for power projects				
Annual Fuel Consumption (in MMcf or Thousand Tons) - Required for non-power projects	1,691.9	1,573.1	1,450.2	1,757.2
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)				
EPC (in thousand dollars)	993,200	764,040	746,040	812,569
Owner's Contingency (% of EPC Costs)	5%	5%	5%	5%
Development Fee (% of EPC Costs)	1.23%	1.23%	1.23%	1.23%
Start-up (% of EPC Costs)	1.50%	1.50%	1.50%	1.50%
Owner's Cost (in thousand dollars) - Land	$250	$200	$200	$200
Additional Capital Cost - Spares	$11,000	$11,000	$11,000	$11,000
Additional Cost #1 - Duties, Taxes, Insurance, etc.	$1,650	$1,650	$1,650	$1,650
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent -To be verified during project development. (in thousand dollars)	$49,660	$38,202	$37,302	$40,628
Operating Costs and Expenses				
Variable O&M (% of EPC Cost) - **HIGHLY CONFIDENTIAL**				
Fixed O&M Cost (% of EPC Cost) - Staffing - **HIGHLY CONFIDENTIAL**				
Additional Comments: When the average daily input and output flow rates, as calculated by the availability analysis, are supplied, the guaranteed plant availability should be set to 100.0%.	Subtask 1.2 - Non-optimized Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Optimized Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Minimum Cost Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Spare Solids Processing Petroleum Coke IGCC Coproduction Plant

Table C2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3
(Page 1 of 4)

Project Name / Description	Subtask 1.2 on 1.3 Basis	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Processing Case
Project Location	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast
Project Type/Structure	BOO	BOO	BOO	BOO

Capital Structure				
Percentage Debt	80%	80%	80%	80%
Percentage Equity	20%	20%	20%	20%
Total Debt Amount (in thousand dollars) - **CALCULATED**	---	---	---	---

Project Debt Terms				
Loan 1: Senior Debt				
% of Total Project Debt **(total for Loans 1,2, and 3 must = 100%)**	100%	100%	100%	100%
Loan Amount (in thousand dollars) - **CALCULATED**	---	---	---	---
Interest Rate	10%	10%	10%	10%
Financing Fee	3%	3%	3%	3%
Repayment Term (in Years)	15	15	15	15
Grace Period on Principal Repayment	0	0	0	0
First Year of Principal Repayment	2003	2003	2003	2003
Loan 2: Subordinated Debt				
% of Total Project Debt	0%	0%	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0	0	0
Interest Rate	8%	8%	8%	8%
Financing Fee	3%	3%	3%	3%
Repayment Term (in Years)	15	15	15	15
Grace Period on Principal Repayment	1	1	1	1
First Year of Principal Repayment	2004	2004	2004	2004
Loan 3: Subordinated Debt				
% of Total Project Debt	0%	0%	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0	0	0
Interest Rate	7%	7%	7%	7%
Financing Fee	3%	3%	3%	3%
Repayment Term (in Years)	10	10	10	10
Grace Period on Principal Repayment	1	1	1	1
First Year of Principal Repayment	2004	2004	2004	2004

Loan Covenant Assumptions				
Interest Rate for Debt Reserve Fund (DRF)	5%	5%	5%	5%
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	Yes	Yes	Yes	Yes
Percentage of Total Debt Service used as DRF	20%	20%	20%	20%

Depreciation				
Construction (Years)	7	7	7	7
Financing (Years)	7	7	7	7

Working Capital				
Days Receivable	30	30	30	30
Days Payable	30	30	30	30
Annual Operating Cash (in thousand dollars)	50	100	100	100
Initial Working Capital (% of first year revenues)	0%	0%	0%	0%

ECONOMIC ASSUMPTIONS

Cash Flow Analysis Period				
Plant Economic Life/Concession Length (in Years)	20	20	20	20
Discount Rate	12%	12%	12%	12%

Escalation Factors

Table C2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3
(Page 2 of 4)

Project Output/Tariff				
Syngas	1.7%	1.7%	1.7%	1.7%
Electricity: Capacity Payment	1.7%	1.7%	1.7%	1.7%
Electricity: Energy Payment	1.7%	1.7%	1.7%	1.7%
Steam	3.1%	3.1%	3.1%	3.1%
Hydrogen	3.1%	3.1%	3.1%	3.1%
Carbon Monoxide	1.7%	1.7%	1.7%	1.7%
Elemental Sulfur	0.0%	0.0%	0.0%	0.0%
Slag Ash	0.0%	0.0%	0.0%	0.0%
Fuel (IGCC output)	0.0%	0.0%	0.0%	0.0%
Chemicals - **Natural Gas**	3.9%	3.9%	3.9%	3.9%
Environmental Credit	1.7%	1.7%	1.7%	1.7%
Other - **Flux**	1.7%	1.7%	1.7%	1.7%
Fuel/Feedstock				
Gas	3.9%	3.9%	3.9%	3.9%
Coal	1.2%	1.2%	1.2%	1.2%
Petroleum Coke	0.0%	0.0%	0.0%	0.0%
Other/Waste	2.3%	2.3%	2.3%	2.3%
Operating Expenses and Construction Items				
Variable O&M	2.3%	2.3%	2.3%	2.3%
Fixed O&M	2.3%	2.3%	2.3%	2.3%
Other Non-fuel Expenses	2.3%	2.3%	2.3%	2.3%

Tax Assumptions				
Tax Holiday (in Years)	0	0	0	0
Income Tax Rate	40%	40%	40%	40%
Subsidized Tax Rate (used as investment incentive)	0%	0%	0%	0%
Length of Subsidized Tax Period (in Years)	0	0	0	0

FUEL/FEEDSTOCK ASSUMPTIONS

Fuel Price				
Gas ($/Mcf)	2.60	2.60	2.60	2.60
Coal ($/Ton)	22.0	22.0	22.0	22.0
Petroleum Coke ($/Ton)	0.00	0.00	0.00	0.00
Other/Waste ($/Ton)	14.00	14.00	14.00	14.00

Heating Value Assumptions				
HHV of Natural Gas (Btu/cf)	1,000	1,000	1,000	1,000
HHV of Coal (Btu/kg)	23,850	23,850	23,850	23,850
HHV of Petroleum Coke (Btu/kg), Dry basis	32,735	32,735	32,735	32,735
HHV of Other/Waste (Btu/kg)	0	0	0	0

TARIFF ASSUMPTIONS

INITIAL TARIFF LEVEL (In Dollars in the first year of construction)				
Syngas ($/Mcf)	$0	$0	$0	$0
Capacity Payment (Thousand $/MW/Year)	$0	$0	$0	$0
Electricity Payment ($/MWh)	$27.00	$27.00	$27.00	$27.00
Steam ($/Ton)	$5.60	$5.60	$5.60	$5.60
Hydrogen ($/Mcf)	$1.30	$1.30	$1.30	$1.30
Carbon Monoxide ($/Mcf)	$0.2274	$0.2274	$0.2274	$0.2274
Elemental Sulfur ($/Ton)	$30.00	$30.00	$30.00	$30.00
Slag Ash ($/Ton)	$0	$0	$0	$0
Fuel ($/Ton)	$0	$0	$0	$0
Chemicals - **Natural Gas ($/Mscf)**	$2.60	$2.60	$2.60	$2.60
Environmental Credit ($/Ton)	$0	$0	$0	$0
Other ($/Ton) - **Flux**	$5.00	$5.00	$5.00	$5.00

CONSTRUCTION ASSUMPTIONS

Construction Schedule

Table C2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3
(Page 3 of 4)

Construction Start Date	1/1/1999	7/1/1999	7/1/1999	7/1/1999
Construction Period (in months) - Maximum of 48	48	42	42	42
Plant Start-up Date *(must start on January 1)*	1/1/2003	1/1/2003	1/1/2003	1/1/2003

Percentage Breakout of Cost over Construction Period (each category must total 100%)				
Year 1				
EPC Costs - See Note 1.	14.655%	9.770%	9.770%	9.770%
Initial Working Capital	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%
Development Fee	0%	0%	0%	0%
Start-up Costs	0%	0%	0%	0%
Initial Debt Reserve Fund	0%	0%	0%	0%
Owner's Cost - Land	70%	70%	70%	70%
Additional Capital Costs - Spares	0%	0%	0%	0%
Financing Fee	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	14.655%	9.770%	9.770%	9.770%
Year 2				
EPC Costs - See Note 1.	35%	35%	35%	35%
Initial Working Capital	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%
Development Fee	100%	100%	100%	100%
Start-up Costs	0%	0%	0%	0%
Initial Debt Reserve Fund	0%	0%	0%	0%
Owner's Cost - Land	30%	30%	30%	30%
Additional Capital Costs - Spares	0%	0%	0%	0%
Financing Fee	100%	100%	100%	100%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	35%	35%	35%	35%
Year 3				
EPC Costs - See Note 1.	30.69%	30.69%	30.69%	30.69%
Initial Working Capital	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%
Development Fee	0%	0%	0%	0%
Start-up Costs	30%	30%	30%	30%
Initial Debt Reserve Fund	0%	0%	0%	0%
Owner's Cost - Land	0%	0%	0%	0%
Additional Capital Costs - Spares	0%	0%	0%	0%
Financing Fee	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	30.69%	30.69%	30.69%	30.69%
Year 4				
EPC Costs - See Note 1.	20.46%	26.16%	26.16%	26.16%
Initial Working Capital	100%	100%	100%	100%
Owner's Contingency	100%	100%	100%	100%
Development Fee	0%	0%	0%	0%
Start-up Costs	70%	70%	70%	70%
Initial Debt Reserve Fund	100%	100%	100%	100%
Owner's Cost - Land	0%	0%	0%	0%
Additional Capital Costs - Spares	100%	100%	100%	100%
Financing Fee	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	20.46%	26.16%	26.16%	26.16%

Table C2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3

Plant Ramp-up Option (Yes or No)	Yes	Yes	Yes	Yes

Start-Up Operations Assumptions (% of Full Capacity)				
Year 1, First Quarter	25.0%	25.0%	25.0%	25.0%
Year 1, Second Quarter	50.0%	50.0%	50.0%	50.0%
Year 1, Third Quarter	75.0%	75.0%	75.0%	75.0%
Year 1, Fourth Quarter	90.0%	90.0%	90.0%	90.0%
Year 1 Average Capacity %	60.0%	60.0%	60.0%	60.0%
Year 2, First Quarter	100.0%	100.0%	100.0%	100.0%
Year 2, Second Quarter	100.0%	100.0%	100.0%	100.0%
Year 2, Third Quarter	100.0%	100.0%	100.0%	100.0%
Year 2, Fourth Quarter	100.0%	100.0%	100.0%	100.0%
Year 2 Average Capacity %	100.0%	100.0%	100.0%	100.0%

CONVERSION FACTORS	
kJ to Btu	0.94783
Btu to kWh	3,413
kg to English Ton	1,016
kW per MW	1,000
kJ/kWh	3,600
Gallons Equivalent to 1 Barrel of Crude Oil	42
Cubic Feet to Cubic Meter	0.02832
Months per Year	12
Hours per Day	24
10^6 (for conversion purposes)	1,000,000
Hours per year	8,760

Note 1. The total is greater than 100% to account for inflation during construction.

Appendix D - Subtask 1.3 Next Plant

Next Optimized Petroleum Coke IGCC Coproduction Plant

Appendix D (Subtask 1.3 Next Plant)

Executive Summary

Global Energy's Wabash River Coal Gasification Repowering Program IGCC plant is one of the cleanest and most efficient coal fueled power plants in the United States. This plant currently operates on both coal and delayed petroleum coke. Bechtel and Global Energy (under Department of Energy sponsorship) used the Wabash River plant as a starting design and cost estimate basis to design an optimized petroleum coke IGCC coproduction plant. This optimized petroleum coke IGCC coproduction plant consumes 5,400 TPD of dry petroleum coke and produces 461 MW of electric power, 371.8 TPD of sulfur, and 80 MMscfd of hydrogen and 980,000 lb/hr of 700 psig / 750^{o}F steam for an adjacent petroleum refinery.

The above optimized plant design was developed in three steps. In the first step, a greenfield plant processing Illinois No. 6 coal was developed to provide current cost information for a plant configuration that is equivalent to the Wabash River Coal Gasification Repowering Program facility. This step produced a design and current cost information for the entire plant including the existing items (or their equivalent) that were reused during the repowering project. The second step generated a non-optimized plant configuration for a petroleum coke IGCC coproduction plant located on the U. S. Gulf Coast. This plant based on current Wabash technology produces about double the amount of power as well as hydrogen and steam for sale to an adjacent petroleum refinery.

In the third step (originally the final step), Value Improving Paractices (VIP) procedures were implemented by bringing together Bechtel's process design and construction experts, Global Energy's experts, and operating and maintenance personnel from the Wabash River facility to form evaluation teams to optimize the plant design. The design employs several process design changes coupled with state-of-the-art equipment and technology to increase efficiency and to reduce construction and operating costs. The net result of these improvements is a simpler, more efficient, less polluting, and less costly IGCC coproduction plant.

The resulting design (designated as the Subtask 1.3 Base Case) includes sparing of the gasification reactors to minimize reactor outages during maintenance or significant forced outages of the reactors. This lead to evaluation of two alternate options: a minimum cost case and a spare gasification train case. Additional reviews and a NPV analysis showed that dry filters were beneficial. Since the base case was no longer the preferred case, it was decided to consolidate the above findings and to develop a single new case called the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant.

The performance of the Subtask 1.3 Next Plant is similar to the other Subtask 1.3 designs with all prior VIP improvements being realized. The Subtask 1.3 Next Plant consumes

5,417 TPD of dry petroleum coke and produces 474 MW of electric power, 373.4 TPD of sulfur, and 80 MMscfd of hydrogen and 980,000 lb/hr of 700 psig / 750^{o}F steam for an adjacent petroleum refinery. In addition, there is a slight availability improvement for the Subtask 1.3 Next Plant over the other Subtask 1.3 designs.

The Subtask 1.3 Next Plant design is expected to have a return on investment of about 13% This is based on a current day economic scenario with a 27 $/MW-hr export power price, $2.60 MMBtu (HHV) natural gas price, and an 8% loan interest rate. Under these conditions large, base loaded, petroleum coke IGCC coproduction plants should be competitive in today's marketplace. Furthermore, the Next Plant design will greatly benefit from higher natural gas and/or electricity prices.

Appendix D (Subtask 1.3 Next Plant)
Table of Contents

Appendix A – Optimized Petroleum Coke IGCC Coproduction Plant

Section 1
Introduction

The objective of this Gasification Plant Cost and Performance Optimization Project is to develop optimized engineering designs and costs for several Integrated Gasification Combined Cycle (IGCC) plant configurations. These optimized IGCC plant systems build on the commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project.[1] The Wabash River Repowering Project consists of a nominal 2,500 TPD E-GAS^{TM} gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

Task 1 of this IGCC Plant Cost and Performance Optimization study consists of the following nine subtasks:

- Subtask 1.1 – Expand the Wabash River Project facility design to a greenfield unit
- Subtask 1.2 – Coke based IGCC plant with the coproduction of steam and hydrogen
- Subtask 1.3 – Optimized coke based IGCC plant with the coproduction of steam and hydrogen
- Subtask 1.4 – Optimized coal to power IGCC plant
- Subtask 1.5 – Comparison between single-train coal and coke fueled IGCC power plants
- Subtask 1.6 – Optimized coal fueled 1,000 MW IGCC power plant
- Subtask 1.7 – Optimized single-train coal to hydrogen plant
- Subtask 1.8 – Review the status of warm gas clean-up technology applicable to IGCC plants
- Subtask 1.9 – Discuss the Value Improving Practices availability and reliability optimization program

During the Subtask 1.3 optimization effort the project team applied Global Energy's design and operation experience coupled with Bechtel's design template approach and Value Improving Practices procedures to reduce plant costs. Specific goals were to lower total installed costs, shorten schedules, and reduce maintenance costs for a plant which is environmentally sound with very low air emissions. This should maximize the Net Present Value (NPV), and thereby create market opportunities for Global's E-GAS^{TM} gasification technology.

The VIP procedures were implemented by bringing together Bechtel's process design and construction experts, Global Energy's experts, and operating and maintenance personnel from the Wabash River facility to form evaluation teams. The following VIP procedures were implemented during the VIP process:

- Technology Selection,
- Process Simplification,
- Classes of Plant Quality
- Process Availability Modeling
- Design-to-Capacity
- Plant Layout Optimization, Constructability Review, and Schedule Optimization
- Predictive Maintenance and Operations Savings

[1] "Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, August 2000.

- Traditional Value Engineering.

The scope of Subtask 1.3 is to revise the Subtask 1.2 facility to develop an Optimized Petroleum Coke IGCC Plant producing steam and hydrogen for the adjacent petroleum refinery in addition to electric power. The plant is located at a generic U. S. Gulf Coast location adjacent to an existing petroleum refinery. Previously, three Subtask 1.3 sub-cases were developed, a base case and two alternate cases.

1. Base Case – This case has two parallel gasification trains with each gasification train containing a spare gasification reactor vessel that can be placed in service when the other vessel requires lengthy maintenance, such as refractory replacement.
2. Minimum Cost Case – This case is similar to the Base Case except that it does not have the spare gasification reactor vessels.
3. Spare Gasification Train Case – This case has three parallel gasification trains. The downstream section of the plant is sized so that it can only process the full output from two syngas generation trains. Thus, one the three syngas generation trains is kept in reserve to replace an operating train when it has an outage and needs maintenance. Once the maintenance work is complete, the train that was taken off line now is the spare train.

After the design of the above Subtask 1.3 plants were completed, several improvements were developed resulting in the development of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant. This plant incorporates the following major changes to the previous Subtask 1.3 plant designs:

1. An advanced dry particulate removal system consisting of a cyclone followed by dry char filters replaced the hybrid dry/wet particulate removal system that was used in the previous spare gasification train case. Dry particulate removal eliminates the need to use the wet scrubber column for particulate removal and the wet particulate recycle to the slurry feed system which results in cost reductions and improved efficiency.
2. Only two wet scrubbing columns are used instead of the three that were used in the spare gasification train case.
3. Reduced operating and maintenance expenses resulting from the advanced dry particulate removal system.

This report describes the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant. An earlier Subtask 1.3 progress report (April 2001) described the previous three Subtask 1.3 cases: the Base Case, the Minimum Cost Case, and the Spare Gasification Train Case.[2] Therefore, this report concentrates on the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant.

Section 2 of this report starts out by briefly describing the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant as a basis for comparison with the current work. This is followed by a description of the spare gasification train Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant case since it is most comparable to the current case. The other two previous Subtask 1.3 cases are not discussed because they have been previously described, and have lower ROIs.

[2] Draft Task 1 Progress Report – Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant, Gasification Plant Cost and Performance Optimization, Contract No. DE-AC26-99FT40342, April 2001.

Section 3 describes the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant and compares its performance with the previously described two cases.

Section 4 describes the results of the financial analysis for the Subtask 1.3 next optimized case plant, the spare gasification train plant, and the non-optimized petroleum coke IGCC coproduction plant.

Section 5 summarizes the results.

Appendix A to this report contains the design and cost information for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant in more detail than is contained in the body of this report. The appendix includes:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the IGCC facility
- Artist's view of plant site
- Overall material, energy, and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

Appendix B contains the financial model input parameters for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant and the other Subtask 1.3 cases.

Section 2
Previous Petroleum Coke IGCC Coproduction Plants

2.1 Subtask 1.2 Non-optimized Plant

The non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant design was developed based on the Wabash River Repowering Project design. The primary purpose of this plant design was to provide a basis for optimizing the design of the Subtask 1.3 plant. The non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant was designed under the premise that the steam and hydrogen products that it produces can be sold to an adjacent petroleum refinery must have a high reliability. Because a single gasification train with backup natural gas firing can satisfy the refinery steam and hydrogen requirements by sacrificing electric power production, all critical parts of the plant were replicated to provide high reliability of a single gasification train. For example, the slurry preparation, slurry storage, slurry pumping and heating sections contain two duplicate trains each with sufficient capacity for the entire plant. The entire gasification area including the acid gas removal area, sulfur recovery facilities, and hydrogen production facilities consist of three duplicate trains each with a capacity of 50% of the total plant design capacity.[3] Figure 1 is a simplified train flow diagram showing the replication of various plant sections in the non-optimized plant.

This plant is located on the U. S. Gulf Coast adjacent to a petroleum refinery. It sells steam, hydrogen, and fuel gas to the refinery, and gets it coke supply directly from the refinery by conveyor.

The complete design and performance of the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant has been described in a previous report.[4] Table 1 summarizes the major plant input and output streams. The plant consumes 5,249 t/d of dry petroleum coke and produces 395.8 MW of electric power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 367 t/d of sulfur. It also produces 99.6 MMscfd of a low Btu fuel gas (87 Btu/scf HHV) for sale to the adjacent petroleum refinery.

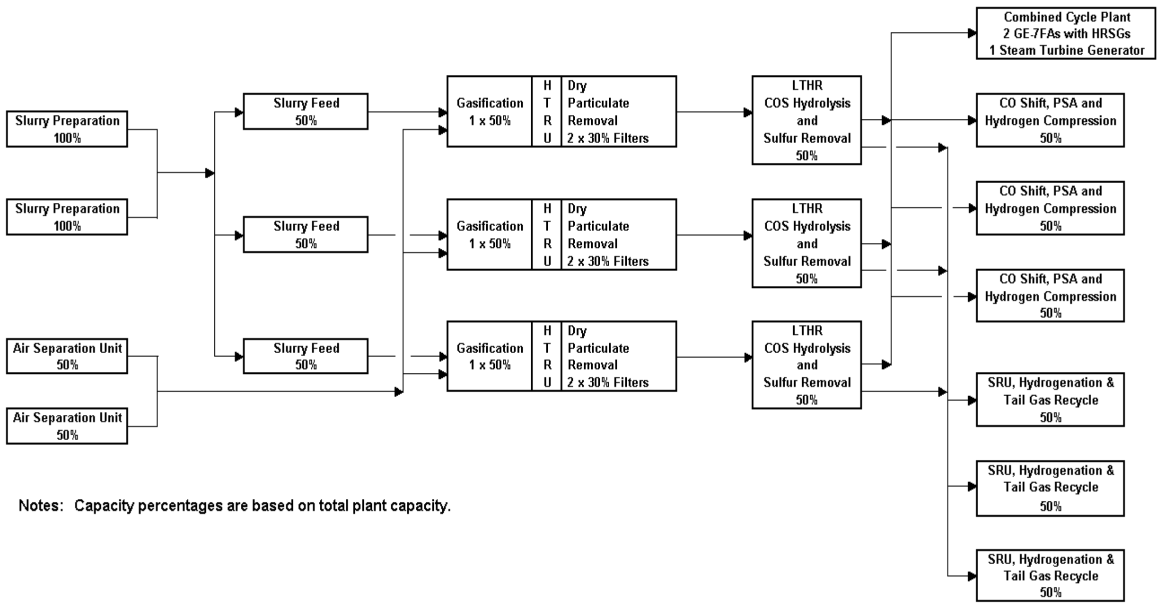
The Subtask 1.2 plant uses two GE 7FA gas turbines; the same gas turbine as used at the Wabash River facility. A modern and more efficient steam turbine that is appropriately sized for this application is used rather than the 1953 vintage steam turbine that was repowered at Wabash River. New petroleum coke receiving and storage facilities were designed to replace the coal facilities since the Wabash River Repowering Project used the existing facilities. New fresh water treatment facilities also were designed to handle the plant makeup river water. New waste water cleanup facilities also were designed to allow compliance with water discharge criteria and commingling of waster water with the refinery waste water outfall.

[3] Capacity references are to the total plant design capacity.
[4] Subtask 1.2 Progress Report, July 2000.

Figure 1

Subtask 1.2 - Train Block Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

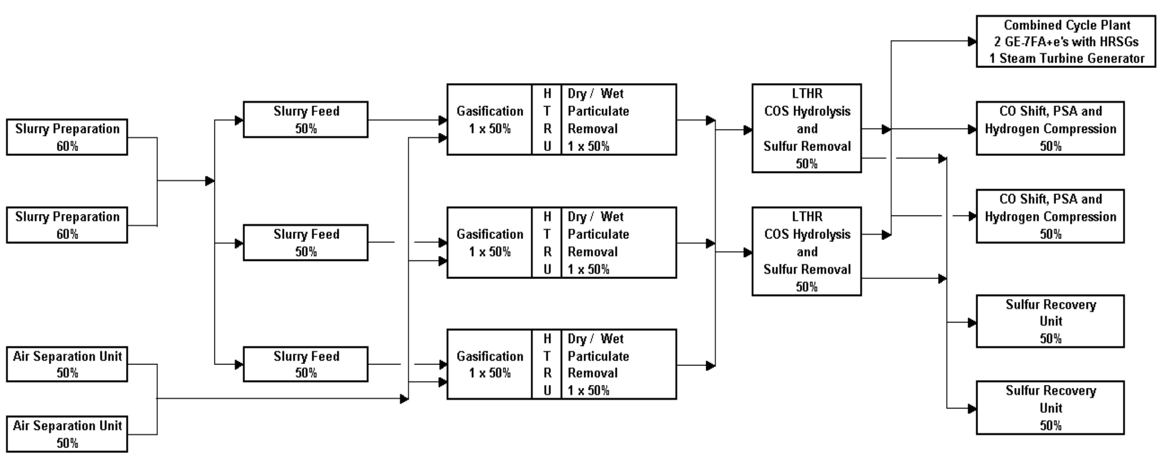


Notes: Capacity percentages are based on total plant capacity.

Figure 2

Subtask 1.3 Spare Gasification Train - Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

2.2 Subtask 1.3 Optimized Spare Gasification Train Plant

The spare gasification train Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant was developed based on the non-optimized design of the Subtask 1.2 plant. This plant also is located on the U. S. Gulf Coast adjacent to a petroleum refinery. However, several basic design changes were made for the optimized case, namely:

1. Newer GE 7FA+e combustion turbines that have a higher capacity and higher thermal efficiency with lower NOx and CO emissions replaced the GE 7FA gas turbines.
2. The low Btu fuel gas is no longer exported to the refinery, but instead is used in the plant to make high pressure steam which is used to make additional electric power.
3. The post reactor residence vessel was deleted.
4. Hot gas cyclones followed by wet scrubbing system are used to remove particulates from the syngas rather than a dry char filter system similar to that used at Wabash River.
5. The gasifier was modified for full slurry quench to minimize the amount of recycle gas quench. The Wabash River plant uses only recycle gas quench.
6. Equipment replication was removed unless it is economically advantageous to retain the extra equipment.
7. A dome, rather than silos, is used for on-site coke storage.
8. The maximum main steam and hot steam reheat temperatures were increased to improve the steam turbine efficiency.
9. The hydrogen plant was redesigned to be more efficient with improved heat recovery.

In Subtask 1.2, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section, and dry char filters remove particulates. A wet scrubbing column downstream of the dry char filters removes chlorides. In Subtask 1.3, the post reactor residence vessel has been eliminated, and the hot syngas goes directly to the HTHR section. Most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. The remaining particulates and chlorides, as well, are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before they are recycled back to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

The Subtask 1.3 Base Case plant contained two gasification trains with each gasification train having a spare gasification vessel. In addition to the Base Case, two alternate case designs were developed to improve the economics. A Minimum Cost case was developed in which the spare gasification vessel was removed from each train with the expectation that the lower plant cost would compensate for the reduced plant availability and result in a higher ROI. The result was that Minimum Cost case had a lower ROI. The third case contained a spare gasification train which could not be used when the other two trains were running at capacity because of downstream processing constraints. This Spare Gasification Train case had a higher ROI because spare train increased the plant availability by a large enough margin to both cover the increased cost and improve the project ROI. Because the Subtask 1.3 Spare Gasification Train case is most comparable to the current case, it solely will be used for comparison. However, because of limited capacity in the processing areas downstream of the gasification trains, all three Subtask 1.3 plants have the same design input and output rates. They only differ in the amount of sparing and plant cost.

Table 1 summarizes the Subtask 1.3 major plant input and output streams and compares them with those of Subtask 1.2, the non-optimized plant. The optimized plant consumes 5,399 t/d of dry petroleum coke (about 3% more than the non-optimized plant) using about the same size Air Separation Unit and produces 461.5 MW of net electric power (about 17% more than the non-optimized plant) while producing the same amount of hydrogen and steam. Part of the increased power production is attributable to a more efficient design, to higher performance equipment, and to the internal use of the low Btu fuel gas to make additional high pressure steam.

Table 1
Design Input and Output Streams for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant
Plant Input		
Coke Feed, as received TPD	5,515	5,673
Dry Coke Feed to Gasifiers, TPD	5,249	5,399
Oxygen Production, TPD of 95% O_2	5,962	5,917
Total Fresh Water Consumption, gpm	4,800	5,150
Condensate Return from the Refinery, lb/hr	686,000	686,000
Flux, TPD	107	110.2
Plant Output		
Net Power Output, MW	395.8	460.7
Sulfur, TPD	367	371.8
Slag, TPD (15% moisture)	190	194.5
Hydrogen, MMscfd	79.4	80
HP Steam, 700 psig/750^{o}F, lb/hr	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0
MMBtu/hr, (HHV)	363	0

Figure 2 is a simplified train flow diagram showing the replication of various plant sections in the spare gasification train Optimized Petroleum Coke IGCC Coproduction Plant. In this design, there are three identical and parallel trains containing the slurry feed tanks and pumps, gasification vessel, high temperature heat removal equipment (HTRU), and the wet particulate removal system. Each train has a design capacity of 50% of the total plant capacity. The downstream section of the plant is sized so that it can only process the full output from two syngas generation trains. Whenever one train has to be shut down for maintenance, the spare train will be placed in service. Once that train is repaired, it becomes the standby spare train until needed.

Because of various improvements to the Subtask 1.3 design, less scheduled maintenance is required than at the Wabash River facility, and the normal outage period can be shortened from twenty days to two weeks. For each gasification train, the expected annual downtime for scheduled maintenance and refractory replacement is one two-week period and one six-week period for refractory replacement for a total of eight weeks per year. Whenever one train has to be shut down for maintenance, the spare train will be placed in service. Once that train is repaired, it becomes the standby spare train until needed. Therefore, the annual maintenance per train will be reduced to two two-week periods per year for a total of four weeks per year.

Emissions performance of the non-optimized and Optimized Petroleum Coke IGCC Coproduction plants are similar as shown in Table 2. The reduced NOx and CO emissions of the optimized plant are the result of steam dilution and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which also has a higher power output and a higher thermal efficiency.

Table 2
Total Emissions Summary for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,587,700	8,602,300
Emissions		
SOx ppmvd	20	24
SOx as SO_2, lb/hr	306	385
NOx, ppmvd	30	14
NOx as NO_2, lb/hr	325	166
CO, ppmvd	17	15
CO, lb/hr	111	105
CO_2, lb/hr (see note)	1,019,074	1,438,367
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	99.5	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

Compared to the non-optimized plant design, the amount of redundant equipment has been significantly reduced.

- The slurry preparation and pumping areas have been reduced to two 50% trains with two 60% ball mills compared to the non-optimized case which has two 100% trains.
- The gasification, HTHR (high temperature heat removal), and particulate removal (wet scrubbing) areas contain two 50% gasifier trains each with a spare gasifier vessel compared to three 50% trains.
- The three 50% trains in the low temperature heat removal (LTHR), acid gas removal (AGR), and sour water treatment areas have been reduced to two 50% trains for the LTHR and AGR areas, and a single 100% sour water treatment area.

- The hydrogen production area (CO shift and PSA) contains two 50% trains compared to three in the non-optimized plant.
- The hydrogen compression area still contains three 50% hydrogen compressors because of their high maintenance requirements.
- The three 50% trains in the sulfur recovery unit (SRU), hydrogenation, and tail gas recycle areas have been reduced to two 50% trains for the optimized plant.
- Minor reductions of replicated and unnecessary equipment were made in other areas not mentioned above.

The spare gasification train Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant occupies a site area of about 52 acres compared to the non-optimized Subtask 1.2 case which occupies about 71 acres. This is a reduction of 27% in site area.

Table 3 compares the installed cost of the spare gasification train Subtask 1.3 optimized plant with the Subtask 1.2 non-optimized plant.[5]

Table 3
Total Installed Costs of the Optimized Spare Gasification Train and Non-optimized Petroleum Coke IGCC Coproduction Plants

Plant Area	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant
Solids Handling	12,949,000	8,012,000
Air Separation Unit	121,187,000	106,857,000
Gasification	540,956,000	346,498,000
Hydrogen Production	60,981,000	42,931,000
Power Block	226,371,000	230,221,000
Balance of Plant	30,756,000	78,050,000
Total	$ 993,200,000	812,569,000

Note: Because of rounding, some column totals may not add to the total that is shown.

The estimated accuracy of the total installed cost estimate for the Subtask 1.2 plant is on the order of +/-11%. This level of accuracy reflects a high degree of confidence based on the actual costs of the Wabash River gasification and air separation areas as a basis for adjusting the Subtask 1.2 scope. The estimated accuracy for the Subtask 1.3 optimized plant is on the order of +/-10%. This accuracy estimate is better lower because a large number of current vendor quotes for the new and high priced equipment were obtained and that the power block costs are based on a recent Powerline™ Gulf Coast estimate.[6] Because of the current demand for gas turbines, the cost for the two combustion turbines

[5] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.
[6] Powerline is a registered trademark of Bechtel Corporation.

appears high compared to historical data. These accuracy estimates apply only to the total cost and do not apply to the individual areas or parts.

The Subtask 1.3 spare gasification train plant costs about 18% less than the non-optimized Subtask 1.2 plant. However, a side-by-side comparison of the plant area costs between Subtask 1.2 and Subtask 1.3 plants shows some striking differences. For all plant areas, a more accurate cost allocation between the individual process areas and the Balance of Plant grouping was made which put more costs in the Balance of Plant and reduced the cost of the three process areas. The Subtask 1.3 cost for the Solids Handling area is less than that for the Subtask 1.2 case because of a revised design approach and a better allocation of the Balance of Plant items. The Air Separation Unit cost is based on a current vendor quote. The reduction in the Gasification area cost is the result of the reduction in installed replicated equipment and the application of the VIP items to the gasification process. The Hydrogen Production area was completely redesigned and optimized for Subtask 1.3. The increased Power Block cost for Subtask 1.3 is the result of market pricing for the gas turbines.

If the three-train Subtask 1.2 plant were to be built using the Subtask 1.3 optimized gasification train design, that plant would cost about 880 MM$. This is a savings of 113 MM$ or just over 11%, all of which essentially are in the gasification and balance of plant areas.

Section 3
Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant

The Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant was developed from the spare gasification train plant with the following changes:

1. A two-stage dry particulate removal system consisting of a cyclone followed by dry char filters has replaced the hybrid dry/wet particulate removal system that was used in the previous spare gasification train case. In the previous case, the syngas scrubber column serves two purposes. It removes both particulates and chlorides from the syngas. In the next plant case, the scrubber only has to remove water-soluble impurities from the syngas, and since the syngas does not contain any solids, none will accumulate in the wash water and cause operational problems. Consequently, the syngas scrubber column should have a higher on-stream factor. In addition, dry particulate removal eliminates the need for particulate removal in the wet scrubber column, and the associated wet particulate recycle to the slurry feed system which results in cost reductions and improved efficiency.

2. Only two wet scrubbing columns are now used instead of the three that were used in the spare train case, one for each gasification train. Since the syngas leaving the dry char filter system is particulate free, block values now can be used to reliability isolate one gasification train upstream of the wet scrubbers from an operating train without shutting down the entire plant. Thus, this eliminates the need that each gasification train must have a dedicated wet scrubber to produce particulate free syngas, and consequently, only two wet scrubbing columns are required.

3. Reduced operating and maintenance expenses resulting from the advanced dry particulate removal system.

Except for the two major changes just described, the design of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant essentially is the same as the Subtask 1.3 spare gasification train case. Figure 3 is a schematic block flow diagram of the Subtask 1.3 Next Plant. Table 4 compares the design input and output stream flow rates for the Subtask 1.3 optimized and Subtask 1.2 non-optimized petroleum coke IGCC Coproduction Plants. The Subtask 1.3 Next Plant exports over 13 MW more power than the spare gasification train plant (474.0 MW vs. 460.7 MW) from an additional 18 TPD of dry coke (5,414 TPD vs. 5,399 TPD). The design HP steam export rate and the hydrogen production rate are identical. Otherwise, the other input and output flow rates are about the same except for the makeup water rate which is slightly lower.

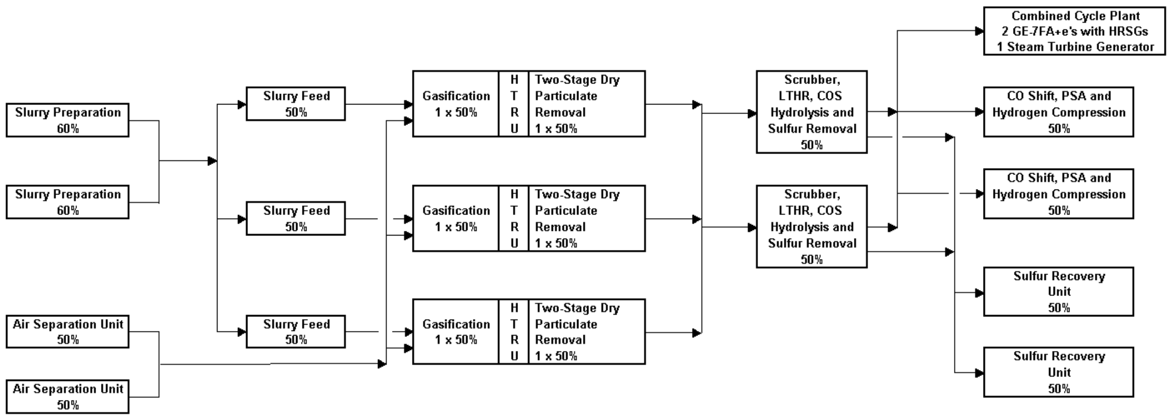
Table 5 compares the total emissions for the Subtask 1.3 optimized and Subtask 1.2 non-optimized petroleum coke IGCC Coproduction Plants. The total emissions for the Subtask 1.3 Next Plant are about the same as those of the Subtask 1.3 optimized spare train plant except for the sulfur emissions. The overall sulfur removal rate still is 99.4%.

The slightly lower percentage sulfur removal for the two optimized plants compared to the Subtask 1.2 plant is the result of selling the low BTU fuel gas from the PSA to the refinery rather than burning it to make power. In the Subtask 1.2, case the sulfur emissions associated with the 99.6 MMscfd of fuel gas that is sold to the refinery becomes a part of the

Figure 3

Subtask 1.3 Next Plant- Train Block Diagram

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

Table 4
Design Input and Output Streams for the Subtask 1.3 Optimized and Subtask 1.2 Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Plant Input			
Coke Feed, as received TPD	5,515	5,673	5,692
Dry Coke Feed to Gasifiers, TPD	5,249	5,399	5,417
Oxygen Production, TPD of 95% O_2	5,962	5,917	5,954
Total Fresh Water Consumption, gpm	4,800	5,150	5,120
Condensate Return from the Refinery, lb/hr	686,000	686,000	686,000
Flux, TPD	107	110.2	110.6
Plant Output			
Net Power Output, MW	395.8	460.7	474.0
Sulfur, TPD	367	371.8	373.4
Slag, TPD (15% moisture)	190	194.5	195.1
Hydrogen, MMscfd	79.4	80	80
HP Steam, 700 psig/750^{o}F, lb/hr	980,000	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0	0
MMBtu/hr, (HHV)	363	0	0

Table 5
Total Emissions Summary for the Subtask 1.3 Optimized and Subtask 1.2 Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,587,700	8,602,300	8,625,800
Emissions			
SOx ppmvd	20	24	22
SOx as SO_2, lb/hr	306	385	350
NOx, ppmvd	30	14	14
NOx as NO_2, lb/hr	325	166	166
CO, ppmvd	17	15	15
CO, lb/hr	111	105	106
CO_2, lb/hr (see note)	1,019,100	1,438,400	1,443,400
VOC and Particulates, lb/hr	NIL	NIL	NIL
Opacity	0	0	0
Sulfur Removal, %	99.5	99.4	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

refinery emissions rather than being a part of the IGCC plant when the fuel gas is burned in the incinerator to make power.

The reduced NOx and CO emissions of both optimized plants are the result of steam dilution and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which also has a higher power output and a higher thermal efficiency.

Table 6 compares the cost of the Subtask 1.3 Next Plant, the Subtask 1.3 optimized spare train plan, and the Subtask 1.2 non-optimized petroleum coke IGCC coproduction plant.[7] The cost of the Subtask 1.3 Next plant is 787.2 MM$, about 31.8 MM$ less than the Subtask 1.3 spare train plant and about 206 MM$ less than the cost of the Subtask 1.2 non-optimized plant. The costs of the solids handling and hydrogen production areas of both Subtask 1.3 plants are identical because these areas essentially are the same in both cases.

The estimated accuracy for the Subtask 1.3 Next Plant is on the order of +/-11%. This accuracy estimate is slightly higher than that of the Subtask 1.3 Base Case because of the extrapolation of the dry char filter costs. As in the Subtask 1.3 Base Case, a large number

[7] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.

of current vendor quotes for the new and high priced equipment were obtained and the power block costs are based on a recent Powerline™ Gulf Coast estimate.[8] Because of the current demand for gas turbines, the cost for the two combustion turbines appears high compared to historical data. This accuracy estimate applies only to the total plant cost and does not apply to the individual areas or parts.

Table 6
Total Installed Costs of the Subtask 1.3 Optimized and Subtask 1.2 Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Plant Area			
Solids Handling	12,949,000	8,012,000	8,012,000
Air Separation Unit	121,187,000	106,857,000	107,246,000
Gasification	540,956,000	346,498,000	312,591.000
Hydrogen Production	60,981,000	42,931,000	42,931,000
Power Block	226,371,000	230,221,000	237,045,000
Balance of Plant	30,756,000	78,050,000	79,420,000
Total	$ 993,200,000	812,569,000	787,246,000

Note: Because of rounding, some column totals may not add to the total that is shown.

[8] Powerline is a registered trademark of Bechtel Corporation.

Section 4
Availability Analysis

The common measures of financial performance, such as return on investment (ROI), net present value (NPV), and payback period, all are dependent on the project cash flow. The net cash flow is the sum of all project revenues and expenses. Depending upon the detail of the financial analysis, the cash flow streams usually are computed on annual or quarterly bases. For most projects, the net cash flow is negative in the early years during construction and only turns positive when the project starts generating revenues by producing saleable products. Therefore, the annual production rate is a key parameter in determining the financial performance of a project. The three previously described Subtask 1.3 cases reflect varying redundancy in design features. This variation affects the projected length of scheduled and forced outages, and consequently, the resulting annual production rates. Thus, a comparative availability analysis is required to predict the relative production rates and corresponding cash flows that are required to develop a meaningful financial analysis of these cases.

4.1 Use of Natural Gas

The gasification trains in Subtask 1.2 plant and the two Subtask 1.3 plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to fully fire one combustion turbine. Thus, in this situation, natural gas is used to supplement the syngas and co-fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption in the plant also is reduced when one gasification train is not operating by the internal power it consumes and the power consumed by one air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

In the less frequent situation when only one syngas train is operating and only one combustion turbine is operable, backup natural gas also is used to fully load the available gas turbine to its natural gas capacity and supply the design hydrogen and steam demands. In this situation, the export power produced by the plant is about half the design rate.

In the least likely situation when both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire the turbine and produce only export electric power from both the combustion turbine and the steam turbine. In this case, the amount of export power will be greater than that of the design capacity of the gas turbine because the internal power loads are greatly reduced.

The average daily natural gas rates are calculated as part of the availability analysis and are shown later in this section in Table 8. Natural gas usage during startup and during maintenance operations, such as for curing refractory, are not considered in the availability analysis calculations, but will be included in the operating and maintenance costs during the financial analysis.

4.2 Availability Analysis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[1] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After three adjustments, this data was used to estimate the availability of the Subtask 1.2 and Subtask 1.3 Petroleum Coke IGCC Coproduction Plant designs. The first adjustment increased the availability of the air separation plant from the observed availability of 96.32% to the industry average availability of 98%. The second adjusted the availability of the first gasification stage to remove a slag tap plugging problem caused by an unexpected change in the coal blend to the gasifier. This adjustment is justified since a dedicated petroleum coke plant would be very unlikely to experience this problem. The third eliminated a short outage that was caused by an outage in the water treatment facility because sufficient treated water storage will be available to handle this type of outage.

Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant and for the two Subtask 1.3 optimized plant designs.[9] The top of Table 7 defines the plant configurations for the three plants. All three plants have a spare gasification train for a total of three trains. Because the Low Temperature Heat Recovery/Acid Gas Removal (LTHR/AGR) area, Sulfur Recovery Unit (SRU), and hydrogen production and purification facilities systems are highly reliable, their spare facilities were eliminated from the Subtask 1.3 plants with only a minor loss in availability. In the Subtask 1.3 Next Plant case, the spare wet chloride scrubbing system also was eliminated.

The bottom of Table 7 contains the calculated availabilities for syngas, power, steam and hydrogen for each of the cases.

For the Subtask 1.2 plant, two gasifiers should be available 77.41% of the time, and only one should be available 99.20% of the time. The resulting equivalent syngas availability is 88.31% (i.e.; syngas production expressed a fraction of the design capacity on an annual basis). Since only one operable train is required to satisfy the refinery hydrogen and steam demands, these items have an equivalent availability of 99.20%, essentially the same as that when one of the two gasifier trains is operating.

The Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant has an equivalent syngas generation capacity of 88.31%. On this basis, the plant has an average daily dry coke consumption of 4,635 TPD dry basis or 88.31% of the design coke consumption of 5,249 TPD.

[9] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304, August 1985.

Table 7
Subtask 1.2 and Subtask 1.3
Plant Configurations and Availabilities

Plant Section	Number of Trains and Section Capacity		
Air Separation Unit (ASU)	2x50	2x50	2x50
Coke Handling	1x100	1x100	1x100
Slurry Preparation	**2x100**	3x60	2x60
Slurry Feed	**3x50**	**3x50**	**3x50**
Gasification (though HTHRU)	**3x50**	**3x50**	**3x50**
Slag Handling	1x100	1x100	1x100
Dry Particulate Removal			
Cyclone		**3x50**	**3x50**
Particulate Filters	**3x(2x30)**		**3x50**
Wet Particulate Removal		**3x50**	
Chloride Scrubbing System	**3x50**		**2x50**
LTHR/AGR	**3x50**	2x50	2x50
SRU	**3x50**	2x50	2x50
Hydrogen	**3x50**	2x50	2x50
Combustion Turbine	2x50	2x50	2x50
Steam Turbine	1x100	1x100	1x100
Scheduled Outages per Train	**16.99%**	**15.34%**	**15.34%**
Spare Gasifier Vessels (1 per train)	**No**	**No**	**No**
Possible Syngas Availability, % (note 3)			
From Two Gasifiers (@100% rate)	84.74%	86.41%	86.85%
From Only One Gasifier (@50% rate)	99.39%	99.58%	99.63%
Equivalent Availability (note 4)	92.07%	93.00%	93.24%
Net Syngas and Power Availability, %			
From Two Gasifiers (@100% rate)	77.41%	78.94%	79.34%
From Only One Gasifier (@50% rate)	99.20%	99.39%	99.44%
Equivalent Availability (note 4)	88.31%	89.17%	89.39%
Equivalent Power Availability (note 4)	94.58%	94.72%	94.61%
Hydrogen and Steam Availability, % (notes 4 & 5)			
Equivalent **Steam** Availability	99.20%	99.39%	99.44%
Equivalent **Hydrogen** Availability (note 6)	99.20%	98.40%	98.45%

Notes:
1. Capacity percentages are based on the total plant design capacity.
2. Based on an average hydrogen plant availability of 99.0%.
3. This is the clean syngas availability without any downstream constraints on consumption or use of the syngas; e.g., when exporting syngas to a pipline.
4. Equivalent availability is the annual average capacity expressed as a fraction of the design capacity.
5. Assumes supplemental firing with natural gas to make maximum use of the combustion and steam turbines.
6. Adding a third 50% hydrogen plant will increase the 100% hydrogen availability to about that of the syngas availability from one gasifier.

The syngas availability from two gasifier trains of the Subtask 1.3 Spare Gasification Train case should be 78.94%, and from only one gasifier train it should be 99.39%. The resulting equivalent syngas availability will be 89.17%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 99.39%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 98.40% because it is reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is 0.14% higher than that of the Subtask 1.2 case even though it contains less spare equipment. The steam availability is about 0.39% higher; and the hydrogen availability is about 0.20% higher. Even though the Subtask 1.3 spare train plant has higher equivalent availabilities than the Subtask 1.2 plant, it has a lower cost that will result in better return on investment (ROI).

The Subtask 1.3 spare train plant has an equivalent syngas generation capacity of 89.17%. On this basis, the plant will have an average daily dry coke capacity of 4,814 TPD dry basis or 89.17% of the design coke consumption of 5,399 TPD. This is an average of 179 TPD more coke than that of the Subtask 1.2 case.

The syngas availability from two gasifier trains of the Subtask 1.3 Next Plant should be 79.34%, and from only one gasifier train it should be 99.44%. The resulting equivalent syngas availability will be 89.39%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 99.44%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 98.45% because it is reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is 0.11% lower than that of the Subtask 1.3 spare train case even though it has a higher syngas availability because the design power production is based on larger steam turbine output that is not realized when backup natural gas is used. The steam availability is about 0.05% higher; and the hydrogen availability is about 0.05% higher also. Even though the Subtask 1.3 Next Plant has higher equivalent availabilities than the Subtask 1.3 spare gasification train plant, it has a lower cost that will result in better return on investment (ROI).

The Subtask 1.3 Next Plant has an equivalent syngas generation capacity of 89.39%. On this basis, the plant will have an average daily dry coke capacity of 4,842 TPD dry basis or 89.39% of the design coke consumption of 5,417 TPD. This is an average of 28 TPD more coke than that of the Subtask 1.3 spare train case and 207 TPD more than the Subtask 1.2 case.

Table 8 compares the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.2 case and the two Subtask 1.3 cases. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and fuel gas product rates, and for the coke and flux feed rates. This is because these design rates are based on two trains running simultaneously. For all cases, the calendar day steam and hydrogen rates are a lot closer to the design rates than the coke, flux, sulfur, and slag rates since only one gasification train has to be operating for the plant to produce the design steam and hydrogen product rates.

Table 8
Design and Daily Average Feed and Product Rates for Subtasks 1.2 and 1.3

	Subtask 1.2 Non-Optimized Plant		Subtask 1.3 Optimized Spare Gasification Train Plant		Subtask 1.3 Next Plant	
Case	Design	Daily Average	Design	Daily Average	Design	Daily Average
Product Rates						
Power, MW	395.8	374.3	460.7	436.4	474.0	448.4
Steam, Mlb/hr	980.0	972.2	980.0	974.1	980.0	974.6
Hydrogen, MMscfd	79.4	78.8	80.0	78.7	80.0	78.8
Sulfur, TPD	367.0	324.1	371.8	331.5	373.4	333.8
Slag, TPD	190.0	167.8	194.5	173.4	195.1	174.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0
Input Rates						
Coke, TPD	5,249	4,635	5,399	4,814	5,417	4842
Flux, TPD	107	94.5	110.2	98.3	110.6	98.9
Natural Gas, MMBtu/d	0	10,099	0	9,303	0	9,059

The daily average natural gas rates shown in Table 8 decrease as the syngas availabilities increase. This is because no natural gas is used when both syngas trains are operating. Thus, they require the least amount of backup natural gas firing. The Subtask 1.3 Next Plant has the highest syngas availability followed by the Subtask 1.3 spare train case.

Section 5
Financial Analysis

The following financial analysis was performed using a discounted cash flow (DCF) model that was developed by Bechtel Technology and Consulting (now Nexant Inc.) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[10] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects.

5.1 Financial Model Input Data

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data that are directly related to the specific plant as follows.

Data Contained on the Plant Input Sheet
- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table B1 contains the plant data that are entered on the Plant Input Sheet for the Subtask 1.2 and the two Subtask 1.3 cases. These data include the use of backup natural gas for firing the combustion gas turbines.

The Scenario Input Sheet contains data that are related to the general economic environment that is associated with the plant as well as some data that are plant related. The data on the Scenario Input Sheet are shown below.

Data Contained on the Scenario Input Sheet
- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Startup information

Table B2 contains the data that are entered on the Scenario Input Sheet for Subtask 1.2 and the two Subtask 1.3 cases.

For all four cases, the EPC spending pattern was adjusted to reflect forward escalation during the construction period since the EPC cost estimate is an “overnight” cost estimate based on mid-year 2000 costs.

[10] Nexant, Inc., “Financial Model User’s Guide – IGCC Economic and Capital Budgeting Evaluation”, Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

For the Subtask 1.3 cases, the construction period has been shortened to 42 months from the 48 month construction period that was used previously for the Subtask 1.2 financial analysis.

Finally, items that were excluded in the cost estimate, such as spares, owners cost, contingency and risk are included in the financial analysis.

5.2 Financial Model Results

Table 9 shows the basic discounted cash flow model results for Subtask 1.2 and the two Subtask 1.3 cases for the conservative price structure contained in Table B2 of Appendix B. With an electric power selling price of 27 $/MW-hr, the Subtask 1.3 Next Plant has the highest after-tax ROI of 9.05% followed by the Subtask 13. spare gasification train case with a ROI of 6.82%. The Subtask 1.2 Minimum Cost case has a negative ROI.

Table 9
Basic Financial Model Results

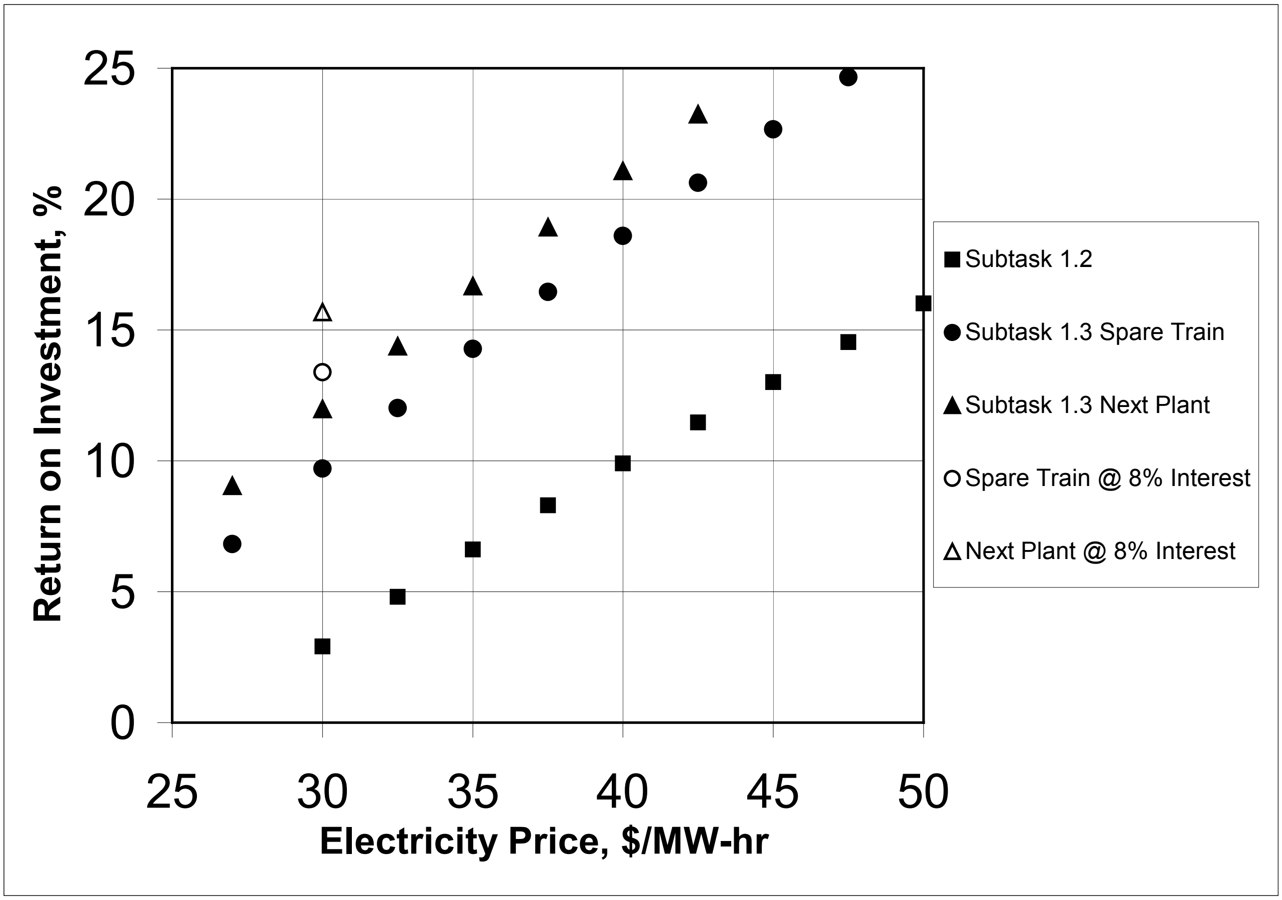
	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Return on Investment with 27 $/MW-hr Power	Negative	6.82%	9.05%
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	32.48	30.02

The second line in Table 9 shows the required electric power selling price that will produce an after-tax ROI of 12%. The Subtask 1.3 Next Plant has the lowest required selling price of 30.02 $/MW-hr (or 3.002 cents/kW-hr). The Subtask 1.3 spare train case has the next lowest required power selling price of 32.48 $/MW-hr. These cases are a significant improvement over the Subtask 1.2 case which has a required power selling price of 43.36 $/MW-hr to produce a 12% after-tax ROI. Thus, the Subtask 1.3 Next Plant has lowered the required power selling price by over 13 $/MW-hr (or 1.4 cents/kW-hr).

Therefore, the Subtask 1.3 Next Plant is the best case because it has the highest return on investment and lowest required power selling price for a 12% after tax ROI.

Figure 4 shows the effect of electric power selling price on the after-tax ROI. As expected, the ROI is a strong function of the selling power price. The Subtask 1.3 ROIs are significantly better than those for Subtask 1.2 reflecting the effects of both the lower costs and higher gasification train availabilities of the Subtask 1.3 cases. The larger slopes of the Subtask 1.3 ROIs are a result of the lower capital costs of the Subtask 1.3 cases compared to the Subtask 1.2 case. The Subtask 1.3 cases have similar slopes because they have closer installed costs. As seen from the figure, the Subtask 1.3 Next Plant must have a required electric power selling prices of about 33.2 $/MW-ht for a 15% after tax ROI, and the Subtask 1.3 spare gasification train case must have a required electric power selling price of about 35.8 $/MW-hr for a 15% after-tax ROI.

Figure 4
Effect of Power Selling Price on the Return on Investment



The solid points in Figure 8 are based on an 80% loan at a 10% interest rate and a 3% financing fee. The open points are based on a 8% loan interest rate and the same 3% financing fee. Reducing the loan interest rate increases the after-tax ROI by about 3.7%. The ROI for the Subtask 1.3 Next Plant increases to about 15.7% with a 30 $/MW-hr power selling price, and that for the spare train case increases to 13.4%.

Figure 5 shows the combined effect of changes in the natural gas price, steam, hydrogen, low Btu fuel gas, and power prices on the ROI for the four cases as a function of the product price index. Table 10, based on in-house correlations, shows the relationship between product price index and the five commodity prices.

This figure shows that with a 5% increase in the product price index, the natural gas price increases to 2.73 $/MMBtu, and the Subtask 1.3 Next Plant has an ROI of about 11.6%. At a 5.7% increase in the product price index, the natural gas price rises to 2.75 $/MMBtu, and the Subtask 1.3 Next Plant has an ROI of 12.0%. It would take a gas price of 2.87 $/MMBtu, corresponding to a 1.1 product price index, for the spare train case to have a 12% ROI.

Figure 5
Effect of Natural Gas Price and Associated Product Prices on the Return on Investment

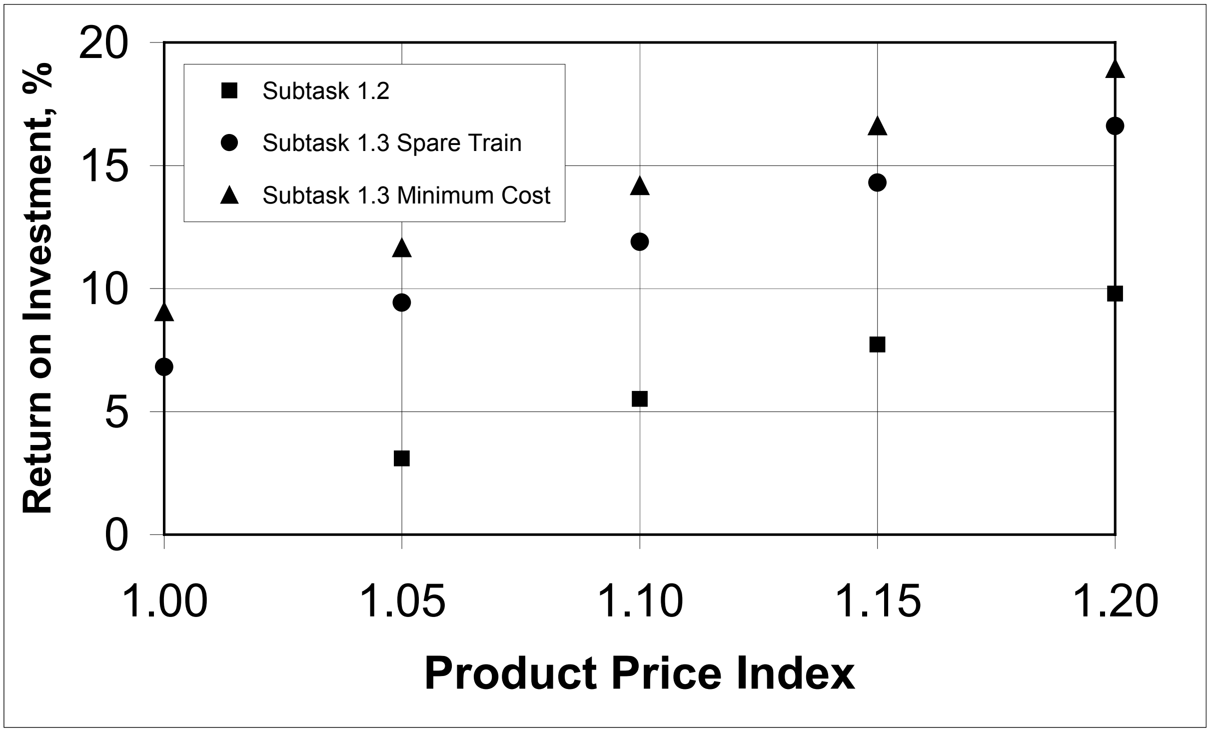


Table 10
Product Price Index and Commodity Prices

Product Price Index	Natural Gas, $/MMBtu	Power, $/MW	Hydrogen, $/Mscf	Steam, $/ton	Fuel Gas, $/Mscf
1.00	2.60	27.00	1.30	5.60	0.2274
1.05	2.73	28.35	1.43	5.88	0.2388
1.10	2.86	29.70	1.58	6.16	0.2501
1.15	2.99	31.05	1.69	6.44	0.2615
1.20	3.12	32.40	1.82	6.72	0.2729

5.3 Current Economic Scenario

Currently, the United States is in a period of low inflation, and as a result, interest rates are very low. Table 11 shows the effect of reducing the loan interest rate to 8% from 10% while still maintaining the same 3% upfront financing charge.

The first line of Table 11 shows the ROI at a 27$ MW power selling price at an 8% loan interest rate. The ROI for the Subtask 1.3 cases has increased by about 3.6% compared to the previous results at a 10% loan interest rate shown in Table 10. Subtask 1.2 now has a positive ROI of 4.58%.

Table 11
Financial Model Results with an 8% Loan Interest Rate

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Return on investment with 27 $/MW-hr power	4.58	10.48	12.70
Required power selling price for a 12% return on investment	37.52	28.56	26.32
Return on investment with 27 $/MW-hr power and other prices indexed to 3.00 $/MM Btu Natural Gas	8.78%	14.40%	16.61%
Return on investment with all prices indexed to 3.00 $/MM Btu Natural Gas	11.55%	18.15%	20.43%

The second line shows the required power selling prices for a 12% ROI. Compared to the previous results shown in Table 9, the required power prices for the Subtask 1.3 cases have dropped by 3.6 to 5.8 $/MW-hr. The Subtask 1.3 Next Plant now only requires a power selling price of 26.32 $/MW-hr for a 12% ROI, and the Subtask 1.3 spare gasification train case requires a power selling price of 28.56 $/MW-hr for a 12% ROI.

Presently, there are wide variations in the future projections for the price of natural gas. At the present time, a 3.00 $/MMBtu price for natural gas seems to be a reasonable value for economic projections. The next two lines of Table 11 show the effect of indexing the product prices to a 3.00 $/MM Btu natural gas price. The third line shows the return on investment at 27 $/MW-hr power price when the steam, hydrogen, and low Btu fuel gas are indexed to a 3.00 $/MM Btu natural gas price. This indexing of the product prices increases the ROI for all cases by about 4%.

The final line shows the ROI when all the product prices are indexed to a 3.00 $/MMBtu natural gas price. This increases the power price to 31.15 $/MW-hr. In this scenario, the ROIs have increased by another 3 to 4%. The Subtask 1.3 Next Plant has an ROI of 20.43%, and the Subtask 1.3 spare train case now has an ROI of 18.15%.

Section 6
Summary

The objective of Subtask 1.3 is to develop an Optimized Petroleum Coke IGCC Coproduction Plant producing steam and hydrogen for an adjacent petroleum refinery starting from the non-optimized plant that was developed in Subtask 1.2. These IGCC plant systems build on the commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project.

The Subtask 1.2 Petroleum Coke IGCC Coproduction Plant produces 395.8 MW of export power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, 363 MMBtu/hr of a low BTU fuel gas, and 367 TPD of sulfur from 5,249 TPD (dry basis) of petroleum coke. For high reliability, this plant has three gasification and hydrogen production trains feeding two General Electric 7FA combustion turbines. It has an equivalent power availability of 99.58% when natural gas is used as a backup fuel. On a daily average basis, it produces about 474 MW of power from 4,635 TPD of coke and 10,099 MMBtu/hr of natural gas. The estimated cost of this plant is $ 993,200,000 (mid-year 2000 basis). It occupies about 72 acres.

Global Energy's design and operation experience coupled with Bechtel's design template approach and Value Improving Practices (VIP) procedures were employed to improve the plant performance and reduce the plant cost in developing the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant. The VIP procedures were implemented by bringing together Bechtel's process design and construction experts, Global Energy's experts, and operating and maintenance personnel from the Wabash River facility to form evaluation teams. The following VIP procedures were implemented during the VIP process:

- Technology Selection,
- Process Simplification,
- Classes of Plant Quality
- Process Availability Modeling
- Design-to-Capacity
- Plant Layout Optimization, Constructability Review, and Schedule Optimization
- Predictive Maintenance and Operations Savings
- Traditional Value Engineering.

The resulting Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant study developed four different plant designs; a base case, a minimum cost case, a spare train case, and a next plant case.

A previous progress report described the first three of these designs. They all produce 460.7 MW of export power, 80.0 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 372 TPD of sulfur from 5,399 TPD (dry basis) of petroleum coke. All three plants use a hybrid dry/wet scrubbing system for particulate removal. They differ primarily in the amount of spare facilities that they contain. The base case design has two gasification trains with each train containing a spare gasification vessel. The minimum cost case is similar to the base case but it does not contain the spare gasification vessels. The spare gasification train case contains a spare gasification train from the slurry feed pumps through the low temperature heat removal and sulfur recovery sections. However, in this case, the downstream power generation facilities are sized so that only two trains can operate simultaneously.

As expected, an availability analysis of the three designs showed that as the amount of sparing increased, the availability of power and the hydrogen and steam byproducts also increased. An economic analysis showed that this increased availability improved the economics even though the plant cost increased.

After the above three designs were completed, a Subtask 1.3 Next Plant design was developed based on the spare train case, but with the following improvements.

1. An advanced dry particulate removal system consisting of a cyclone followed by dry char filters replaced the hybrid dry/wet particulate removal system that was used in the previous spare gasification train case.
2. Only two wet scrubbing columns are used instead of the three that were used in the spare gasification train case.
3. Reduced operating and maintenance expenses.

The above changes either reduced the plant cost, improved the availability, and/or increased the efficiency so more power could be produced at a lower cost per MW which still supplying the required amounts of steam and hydrogen to the refinery. The following table shows how the return on investment and required power selling price has decreased from the Subtask 1.2 plant through the Subtask 1.3 spare gasification train case to the Subtask 1.3 Next Plant when 80% of the plant is financed with a 10% loan.

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Spare Gasification Train Plant	Subtask 1.3 Next Plant
Return on Investment with 27 $/MW-hr Power	Negative	6.82%	9.05%
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	32.48	30.02

Compared to the Subtask 1.2 case, the required power selling price to produce a 12% ROI has dropped by over 13 $/MW-hr as a result of the improved design resulting from the VIP procedures.

Based on a current day economic scenario with an 8% loan rate, the economics are further improved. The Subtask 1.3 Next Plant now will only require a power selling price of 26.32 $/MW-hr to generate a 12% ROI.

With power prices under 30 $/MW-hr, petroleum coke IGCC coproduction plants can be competitive in today's market.

As one or more of these plants are built, further improvements will be made and they will become even more competitive.

Appendix D

Subtask 1.3 Next Plant (Appendix A)

Next Optimized Petroleum Coke IGCC Coproduction Plant

Subtask 1.3 Next Plant (Appendix A)
Table of Contents

Figures

Subtask 1.3 Next Plant (Appendix A)

Subtask 1.3 – The Next Optimized Petroleum Coke IGCC Coproduction Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7A gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest processing Illinois No. 6 coal. Subtask 1.2 developed a design and current cost for a petroleum coke IGCC coproduction plant producing electric power, hydrogen, steam, and fuel gas at a Gulf Coast location adjacent to a petroleum refinery

This appendix summarizes the results of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant. The scope of Subtask 1.3 next plant is to convert the Subtask 1.3 spare solids train IGCC coproduction plant into the next optimized petroleum coke IGCC coproduction plant producing electric power, hydrogen and steam at a Gulf Coast location adjacent to a petroleum refinery. The plant design was optimized using both Global Energy's petroleum coke experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures.

Bechtel and Global Energy implemented a project specific Value Improving Practices program to reduce the installed and operating costs associated with the plant to develop the design for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant. The VIP team included process design and construction specialists from Bechtel, gasification experts from Global Energy, and operating and maintenance personnel from the Wabash River Repowering Project. The team implemented Value Improving Practices covering the following areas to improve the plant performance and return on investment.

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Design-to-Capacity
- Traditional Value Engineering
- Process Availability (Reliability) Modeling
- Plant Layout Optimization
- Constructability Review / Schedule Optimization
- Operation and Maintenance and Savings

The base case design of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant consists of two parallel gasification trains. As is the case in the Wabash River Repowering Project, each gasification train contains a spare gasifier vessel that can be placed into service when the operating vessel needs extensive maintenance, such as refractory replacement. During the switchover period, maintenance is performed in the other areas of the plant, as required, to minimize the downtime.

During the development of the Subtask 1.3 plant design, two alternate design cases were developed. The first is a minimum cost case in which the spare gasifier vessel is removed from each train. In this case, long turnaround periods are required when it is necessary to replace the refractory in a gasifier, and availability suffers. The other case contains a spare gasification train from the slurry preparation area through the wet particulate scrubbers. Each of these three gasification trains has only one gasifier vessel like the minimum cost case. However, in this case, whenever one train requires maintenance and is shut down, the spare (or idle) train immediately is started up, and the maintenance is performed on the shutdown train while the previously idle train is operating. When the maintenance has been completed on the shutdown train, it now becomes the idle or spare train.

The Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant is based on the spare gasification train plant with the following changes:

1. A two-stage completely dry particulate removal system consisting of a cyclone followed by dry char filters has replaced the hybrid dry/wet particulate removal system that was used in the previous spare gasification train case. In the previous case, the syngas scrubber column serves two purposes. It removes both particulates and chlorides from the syngas. In the next plant case, the scrubber only has to remove water-soluble impurities from the syngas, and since the syngas does not contain any solids, none will accumulate in the wash water and cause operational problems. Consequently, the syngas scrubber column should have a higher on-stream factor. In addition, dry particulate removal eliminates the need for particulate removal in the wet scrubber column, and the associated wet particulate recycle to the slurry feed system which results in cost reductions and improved efficiency.

2. Only two wet scrubbing columns are now used instead of the three that were used in the spare train case, one for each gasification train. Since the syngas leaving the dry char filter system is particulate free, block values now can be used to reliability isolate one gasification train upstream of the wet scrubbers from an operating train without shutting down the entire plant. Thus, this eliminates the need that each gasification train must have a dedicated wet scrubber to produce particulate free syngas, and consequently, only two wet scrubbing columns are required.

3. Reduced operating and maintenance expenses resulting from the advanced dry particulate removal system.

This appendix contains the following design and cost information for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the IGCC coproduction plant
- Artist's view of the plant
- Overall material, energy and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

The following sections describe the results of the design and cost estimate for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant.

Section A2 contains the design basis for the Subtask 1.3 Next Optimized Coke IGCC Coproduction Plant. Section A3 contains descriptions of the various sections of the plant. Section A4 summarizes the overall plant performance. Section A5 contains a listing of the major pieces of equipment within the plant. Section A6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the Next Optimized Petroleum Coke IGCC Coproduction Plant. The design basis for this plant essentially is the same as that of the non-optimized petroleum coke IGCC coproduction plant of Subtask 1.2 except that no fuel gas is exported to the petroleum refinery. This is the same design basis that was used for the other Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plants.

A.2.1 Capacity

The Next Optimized Petroleum Coke IGCC Coproduction Plant will process a nominal 5,400 TPD of delayed petroleum coke (dry basis) to produce syngas that will fully load two GE 7FA+e gas turbines at 70° F ambient, 60% relative humidity, and 14.7 psia, and coproduce about 80 MMscfd of hydrogen. It also will export 980,000 lbs/hr of 750 psig / 700°F steam to an adjacent petroleum refinery.

A.2.2 Site Conditions

Location	Gulf Coast Refinery
Elevation, Ft	25
Air Temperature	
Maximum, °F	95
Annual Average, °F	70
Minimum, °F	29
Summer Wet Bulb, °F	80
Relative Humidity, %	60
Barometric Pressure, psia	14.7
Seismic Zone	0
Design Wind Speed, MPH	120

A.2.3 Feed

Type	Delayed Petroleum Coke	
	Dry Basis	As Rec'd
HHV, Btu/lb	14,848	14,132
LLV, Btu/lb	14,548	13,846
Analysis, Wt%		
Carbon	87.86	83.62
Hydrogen	3.17	3.02
Nitrogen	0.89	0.85
Sulfur	6.93	6.60
Oxygen	1.00	0.95
Chlorine	50 ppm	47 ppm
V & Ni	1900 ppm	1767 ppm
Ash	0.14	0.13
Moisture	NA	4.83
Total	100	100

A.2.4 Water

Cations	mg/l	As equivalent ppm of $CaCO_3$
Calcium	8.4	21
Copper	0.01	
Iron	2.2	3.9
Magnesium	3.0	12.3
Manganese	< 0.06	
Molybdenum	< 0.01	
Potassium	2.0	2.6
Sodium	19.0	41.4
Zinc	0.01	0.02
Sodium (add to balance)	21.1	46.0
Total Cations		127

Anions	mg/l	As equivalent ppm of $CaCO_3$
Carbonate		
Bicarbonate	61.0	50.0
Chloride	16.0	22.6
Sulfide	52.0	54.1
Nitrate - Nitrogen	0.7	0.6
Phosphate	0.6	
Fluoride	no data	
Chloride (add to balance)	0.0	0.0
Total Anions		127

Weak Ions	mg/l	As equivalent ppm of $CaCO_3$
Ammonia Nitrogen	no data	
Total Silica	21.0	

Other Characteristics	mg/l	As equivalent ppm of $CaCO_3$
Total Dissolved Solids (TDS)	202	
Standard Conductivity	271	
Total Alkalinity		50
Total Hardness		33
Total Organic Carbon	12 to 15	
Turbidity	5 to 25	
PH	6.4 to 7.4	
Total Suspended Solids	10 to 60	

A.2.5 Natural Gas

Natural gas will be available for startup and for supplemental firing of the combustion turbines and HRSG. The natural gas will have a HHV of 1,000 Btu/scf and a LHV of 900 Btu/scf.

A.3 Plant Description

A.3.1 Block Flow Diagram

The Next Optimized Petroleum Coke IGCC Coproduction Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification

    - Slurry Preparation
    - Slag Handling
    - Gasifier/High Temperature Heat Recovery (HTHR)/ Cyclone and Dry Char Filter
    - Particulate Removal System
    - Wet Chloride Scrubber
    - Sulfur Removal
    - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block

    - Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG)
    - Steam Turbine Generator (STG)/Auxiliary Equipment

- Hydrogen Production

    - CO Shift
    - Pressure Swing Adsorption (PSA)
    - Hydrogen Compression

- Balance of Plant

Figure A1 is the block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the relative capacity of each train are noted on the BFD.

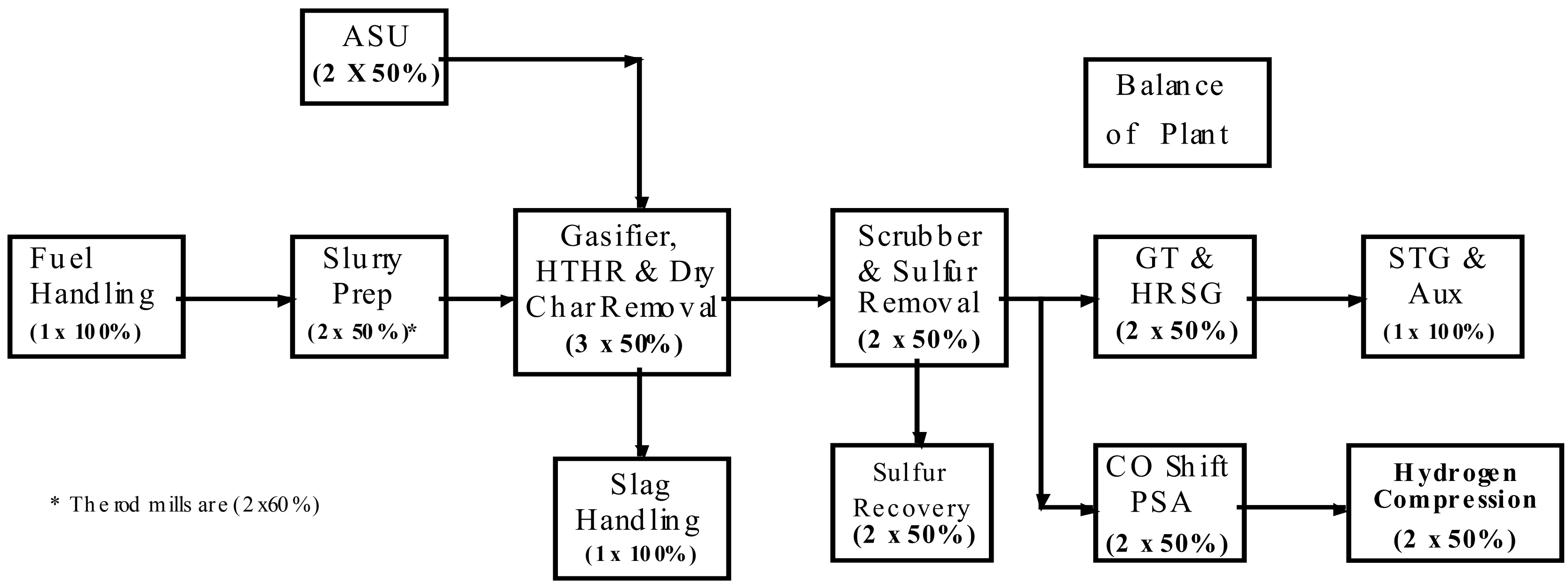
A.3.2 General Description

The plant is divided into the six distinct areas.

- Fuel Handling Unit
- Gasification Plant
- Air Separation Unit
- Power Block
- Hydrogen Plant
- Balance of Plant

Section A.3.3 describes the fuel handling facilities required for transferring petroleum coke from refinery battery limits to on site storage and conveying to the gasification plant.

Figure A1
NEXT OPTIMIZED PETROLEUM COKE IGCC COPRODUCTION PLANT SIMPLIFIED BLOCK FLOW DIAGRAM



Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two stage entrained flow gasifier to convert petroleum coke to syngas. The gasification plant includes a two-stage system to remove impurities from the syngas. The dry char filtration system used at the Wabash River plant to remove char from the syngas has been improved by placing a cyclone ahead of the dry char filters.

Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95% purity oxygen stream is produced as the oxidant for the gasifier. The design is based on the Wabash River plant ASU.

Section A.3.6 describes the power block, which consists of two General Electric 7FA+e model gas turbines with generators from GE. The gas turbines use moisturized syngas and steam injection for NOx control.

Section A.3.7 describes the hydrogen plant, which consists of syngas CO shift units, Pressure Swing Adsorption (PSA) units, and hydrogen compressors.

Section A.3.8 describes the balance of plant (BOP). The BOP portion of the Next Optimized Petroleum Coke IGCC Coproduction Plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Next Optimized Petroleum Coke IGCC Coproduction Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were generated by the Comet model.

A.3.3 AREA 100 – Fuel Handling

The fuel handling system provides the means to receive, unload, store, and convey the delayed petroleum coke to the storage facility.

Crushed petroleum coke (size 2X0) is transferred from the refinery or barge to the coke storage dome by transfer belt conveyors from the battery limit. Flux is delivered by truck at truck unloading hopper and conveyed to the flux storage silo by pneumatic conveyor. Petroleum coke and flux are mixed by the weigh belt feeders and transferred by coke feed conveyors to the day storage bins above the rod mills in the slurry preparation area (area 150).

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur removal. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

The petroleum coke slurry feed for the gasification plant is produced by wet grinding in a pair of 60% capacity rod mills. In order to produce the desired slurry solids concentration, coke is fed to each rod mill with water that is recycled from other areas of the gasification plant. Prepared slurry is stored in agitated tanks.

All tanks, drums and other areas of potential atmosphere exposure of the product slurry or recycled water are covered and vented into the tank vent collection system for vapor emission control.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-GAS Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a horizontal refractory lined vessel into which oxygen and coke and flux slurry are atomized via opposing mixer nozzles. The coke and flux slurry, recycle solids, and oxygen are fed sub-stoichiometrically at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coke is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the coke is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are easily removed by downstream processing.

Mineral matter in the coke and flux form a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows up from the horizontal section into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which additional coke slurry is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This additional coke feed serves to lower the temperature of the gas exiting the first stage by the endothermic nature of the equilibrium reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by additional slurry injection (slurry feed vaporization) instead of syngas recycle which is used at Wabash River. No oxygen is introduced into the second stage.

The gas and entrained particulate matter exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

The raw gas leaving the high temperature heat recovery unit passes through a twp-step cyclone/dry char filter particulate removal system to remove solids from the syngas. The recovered particulates are recycled to the gasifier.

Water soluble impurities are removed from the syngas in a wet scrubber column following the dry char filters.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir in the top of the bin and goes to a settler in which the remaining slag fines are settled. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, and a water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

The scrubbed syngas is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the downstream Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the desired high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a single train with backup sour water feed storage.

A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam stripping at a lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiency.

A.3.4.5 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

Two 50% capacity ASUs are provided to deliver the required oxygen for the coke gasification process. Each ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous production.

A.3.6 Power Block

The major components of the power block include two gas turbine generators (GTG), two heat recovery steam generators (HRSG), a steam turbine generator (STG), and numerous supporting facilities.

A.3.6.1 AREA 500 - Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and stack

Each of the two The combustion turbine generators are General Electric 7FA+e, nominal 210 MW output each. Each GTG utilizes moisturized syngas and steam injection for $NO_{\times}$ control. Combustion exhaust gases are routed from each GTG to its associated HRSG and stack. Natural gas is used as back-up fuel for the gas turbine during startup, shutdown, and short duration transients in syngas supply.

The HRSG receives the GT exhaust gases and generates steam at the main steam and reheat steam energy levels. It generates high pressure (HP) steam and provides condensate heating for both the combined cycle and the gasification facilities.

The HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSG boiler includes a steam drum for proper steam purity and to reduce surge during cold start. Large unheated down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

Each stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 - Steam Turbine (ST)

The reheat, condensing turbine includes an integrated HP/IP opposed flow section and an axial flow LP section. Turbine exhaust steam is condensed in a surface condenser. The reheat design ensures high thermal efficiency and excellent reliability. It produces 164.3 MW of electric power.

A.3.6.3 Power Delivery System

The power delivery system includes the GT generator output at 18 kilovolts (kV) with each connected through a generator breaker to its associated main power step-up transformer. A separate main step-up transformer and generator breaker is included for the ST generator. The HV switch yard receives the energy from the three generator step-up transformers at 230 kV.

Two auxiliary transformers are connected between the GTG breakers and the step-up transformers. Due to the large auxiliary load associate with the IGCP plant, internal power is distributed at 33 kV from the two auxiliary power transformers. The major motor loads in the ASU plants will be serviced by 33/13.8 kV transformers. The balance of the project loads will be served by several substations with 33/4.16 kV transformers supplying double ended electrical bus.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.7 Hydrogen Plant

A.3.7.1 AREA 450 – CO Shift Unit

Hydrogen production by the CO shift reaction is highly exothermic. High temperatures favor fast reaction rates, but result in unfavorable equilibrium conditions. Conversely, low temperatures favor the equilibrium conditions that allow the shift reaction to go to completion and result in low CO levels in the product gas. Also, the maximum allowable reactor outlet temperature must be below the catalyst sintering point and within the limits for practical vessel design. Thus, a two-stage reaction system is used with interstage cooling. The first high temperature shift reactor is designed to achieve high reaction rates at the highest allowable outlet temperature, and the second is designed to give a high conversion at a lower outlet temperature where the equilibrium conditions are more favorable. Approximately 93 percent of the carbon monoxide is converted to hydrogen in the first-stage reactor.

The clean syngas from the syngas moisturizer and preheater goes to the first CO shift reactor. Medium pressure steam is preheated and mixed with the syngas before it goes to the first-stage high temperature shift reactor. Adjusting the rate of steam addition controls the first-stage reactor outlet temperature.

The hot gas leaving the first-stage high temperature shift reactor is cooled by preheating the clean syngas and steam going to the first-stage reactor. It is further cooled before entering the second-stage shift reactor by the generation of medium pressure steam.

The hot gas leaving the second-stage shift reactor is cooled by steam generation producing medium pressure (420 psig) steam. It is further cooled by heating water for the syngas moisturizer, by preheating condensate, and then by a trim water cooler before going to the Pressure Swing Adsorption unit. Process condensate is separated in the knock-out drum and sent to condensate treatment.

Two 50% trains are needed as limited by maximum reactor vessel diameter to provide the required capacity and system reliability.

A.3.7.2 AREA 460 - Pressure Swing Adsorption Unit (PSA)

The shifted gas from the CO shift unit is sent to the pressure swing adsorbers for purification of the hydrogen product. The PSA system is based on the principle of pressure reduction and rapid cycle operation to remove impurities from the adsorbent. It consists of three major parts, i.e., adsorber vessels filled with adsorbent, a prefabricated valve skid, and a control panel containing the cycle control system.

A complete PSA cycle consists of four basic steps: adsorption, depressurization, purge at low pressure, and repressurization. Multiple adsorbent beds are used for high throughputs and hydrogen recovery.

Approximately 80 MMscfd of 99% hydrogen is produced and sent to the hydrogen compressors. The tail gas from the PSA is sent to the incinerator to produce high pressure steam for power generation.

A.3.7.3 AREA 470 - Hydrogen Compression

The hydrogen from the PSA unit is compressed to 1000 psig by the hydrogen compressors and delivered to the adjacent petroleum refinery.

A.3.8 AREA 900 - Balance of Plant

A.3.8.1 Cooling Water System

The design includes two cooling water systems. One provides the cooling duty for the power block. A separate system provides the cooling duty for the air separation unit and equipment cooling throughout the gasification facility.

The major components of the cooling water system consist of a cooling tower and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. Both cooling towers are multi-cell mechanically induced draft towers, sized to provide the design heat rejection at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.8.2 Fresh Water Supply

River water from an industrial water supply network is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.8.3 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, the hydrogen plant, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.8.4 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the refinery waste water system.

A.3.8.5 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The system consists of air compressors, air receivers, hose stations, and piping distribution for each unit. Additionally, the instrument air system consists of air dryers and a piping distribution system.

A.3.8.6 Incineration System

The tank vent stream is composed primarily of PSA sweep gas plus air purged through various in-process storage tanks that may contain small amounts of other gases such as ammonia and acid gas. During process upsets of SRU, tail gas streams can be combined with the tank vent system before treatment in a high temperature incinerator. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.8.7 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.8.8 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC power plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or fiber optics; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, and the coke handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical GT, ST, and generator, and ASU control parameters.

This approach retains control of IGCP equipment used to transport the coke, control turbines and generators, and to support the ASU. Other balance of plant equipment such as air compressors, condenser vacuum pumps, and water treatment use either local PLCs, or contact and relay control cabinets to operate the respective equipment. All remaining plant components are exclusively controlled by the DCS including the HRSG, the gasifier, ASU, hydrogen plant, electrical distribution, and other power block and gasification support systems.

A.3.8.9 Buildings

The plant has a central building housing the main control room, office, training, other administration areas and a warehouse/maintenance area. Other buildings are provided for water treatment equipment and the MCCs. The buildings, with the exception of water treatment, are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment.

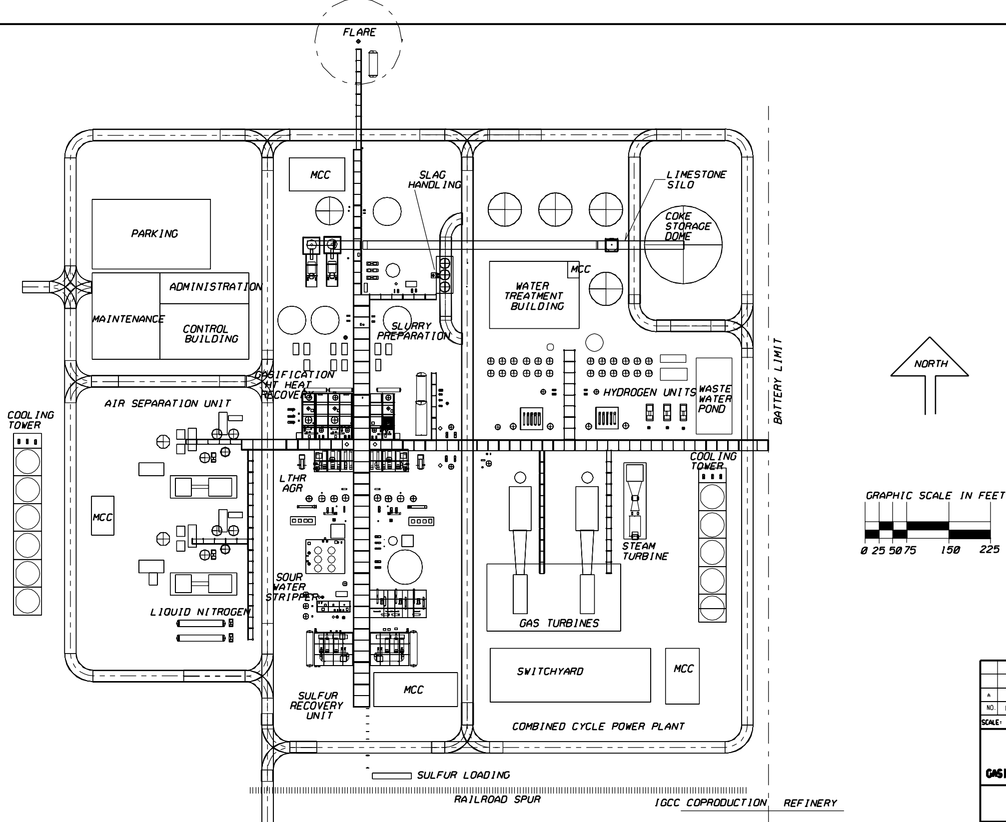
A.3.8.10 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the Next Optimized

Petroleum Coke IGCC Coproduction Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A							

SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

PET-COKE COPRODUCTION PLANT
SUBTASK 1.3 NEXT PLANT

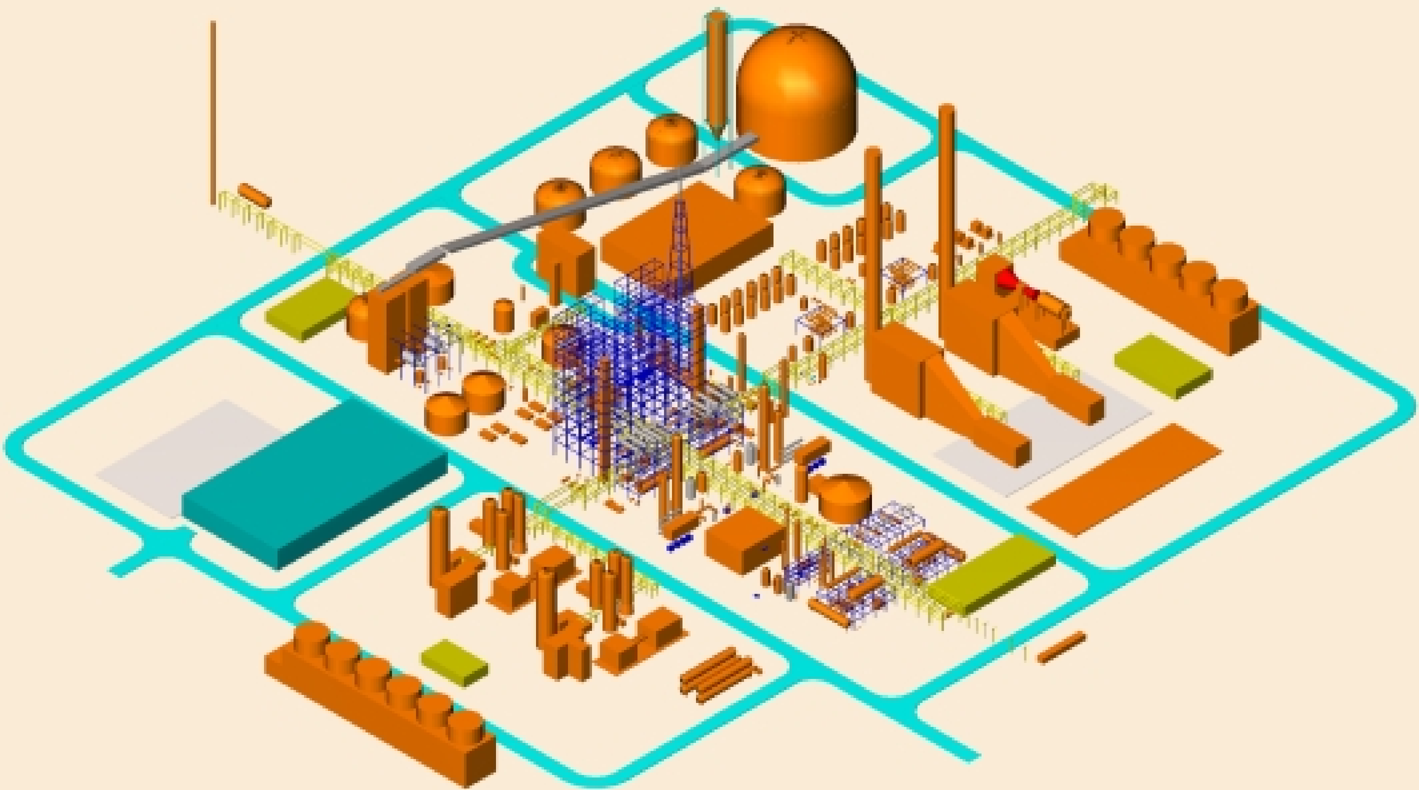
SITE PLAN

JOB NO: 24355-104 DRAWING NO: SK - 00118 REV. A

Figure A3

Artist's Conception of the Next Optimized

Petroleum Coke IGCC Coproduction Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, the Next Optimized Petroleum Coke IGCC Coproduction Plant Detailed Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 5,417 t/d of dry petroleum coke and produces 474 MWe of export electric power, 373.4 t/d of sulfur, 195.1 t/d of slag (containing 15 wt% water), and exports to the adjacent petroleum refinery 80 MMscfd of hydrogen and 980,000 lbs/hr of 700 psig/ 750°F steam. It also consumes110.6 t/d of flux, 686,000 lbs/hr of condensate return from the refinery, and 5,223 gpm of river water.

Figure A5 shows the overall water flow diagram for the plant. This figure provides details of the water usage and losses within the plant. About 1,200 gpm of waste water is sent to the refinery outfall.

A.4.2 Performance Summary

Plant performance is based on the petroleum coke IGCC coproduction plant configuration including a GE 7FA+e gas turbine. Global Energy provided a heat and material balance for these facilities, using the design basis petroleum coke. This information was then integrated with a HRSG and reheat steam turbine. The GT Pro™ computer simulation program was used to simulate combined cycle performance and plant integration.[1]

Table A1 summarizes the overall performance of the Next Optimized Petroleum Coke IGCC Coproduction Plant. As shown in the table, the oxygen input to the gasifiers is 5,954 t/d, and the heat input is 6,703 MMBtu/hr. The two gas turbines produce 420 MW of power from their generators. The steam turbine produces another 164.3 MW of power for a total power generation of 584.3 MW. Internal power usage consumes 110.3 MW leaving a net power production of 474 MW for export.

Table A2 summarizes the expected emissions from the Next Optimized Petroleum Coke IGCC Coproduction Plant. The GE 7FA+e gas turbines and HRSG system has a stack exhaust flow rate of 7,967,000 lb/hr at 258°F. On a dry basis adjusted to 15% oxygen, these gases have a SOx concentration of 3 ppmv, a NOx concentration of 10 ppmv, and a CO concentration of 10 ppmv. The incinerator stack has an exhaust flow rate of 658,800 lb/hr at 500°F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 280 ppmv, a NOx concentration of 40 ppmv, and a CO concentration of 50 ppmv.

The plant emits 8,625,800 lbs/hr of total exhaust gases having an average SOx concentration of 22 ppmv, an average NOx concentration of 14 ppmv, and an average CO concentration of 15 ppmv. Expressed another way, this is 350 lb/hr of SOx (as SO_2), 166

[1] GT Pro is a registered trademark of the Thermoflow Corporation.

lb/hr of NOx (as NO_2), and 106 lb/hr of CO. These emissions are about the same as those of the other Subtask 1.3 cases.

Compared to the non-optimized petroleum coke IGCC coproduction plant of Subtask 1.2, the SOx emissions are slightly higher reflecting the increased coke feed rate. The sulfur removal is 99.4%. The NOx emissions are about half, and the CO emissions are about the same. The CO_2 emissions are about 40% higher than those of Subtask 1.2 because this case does not send the low Btu PSA off gas to the adjacent petroleum refinery for fuel, but instead burns it to produce high pressure steam which is used in the steam turbines to produce power. In Subtask 1.2, the CO_2 emissions associated with the combustion of this low Btu gas would be attributed to the refinery rather than the Petroleum Coke IGCC Coproduction Plant.

Table A1

Performance Summary of the Next Optimized Petroleum Coke IGCC Coproduction Plant

Ambient Temperature, °F	70
Coke Feed, as received, TPD	5,692
Dry Coke Feed to Gasifiers, TPD	5,417
Total Fresh Water Consumption, gpm	5,120
Condensate Returned from the Refinery, gpm	1,372
Flux,TPD	110.6
Sulfur, TPD	373.4
Slag Produced, TPD (15% moisture)	195.1
HP Steam Export, lb/hr	980,000
Hydrogen Production, MMscfd	80
Fuel Gas Export, MMscfd	0
Total Oxygen Feed to the Gasifiers, TPD of 95% O_2	5,954
Heat Input to the Gasifiers (HHV), Btu/hr x 10^6	6,703
Cold Gas Efficiency at the Gas Turbine (HHV), %	77.5
Fuel Input to Gas Turbines, lb/hr	1,016,830
Heat Input to Gas Turbines (LHV), Btu/hr x 10^6	3,592
Steam Injection to Gas Turbines, lb/hr	395,670
Gas Turbines Output, MW	420
Steam Turbine Output, MW	164.3
Gross Power Output, MW	584.3
Gasification Plant Power Consumption, MW	(17.7)
ASU Power Consumption, MW	(70.8)
Balance of Plant & Auxiliary Load Power Consumption, MW	(16.4)
Hydrogen Plant & Compressors, MW	(5.4)
Net Power Output, MW	474.0

Table A2

Environmental Emissions Summary* of the Next Optimized Petroleum Coke IGCC Coproduction Plant

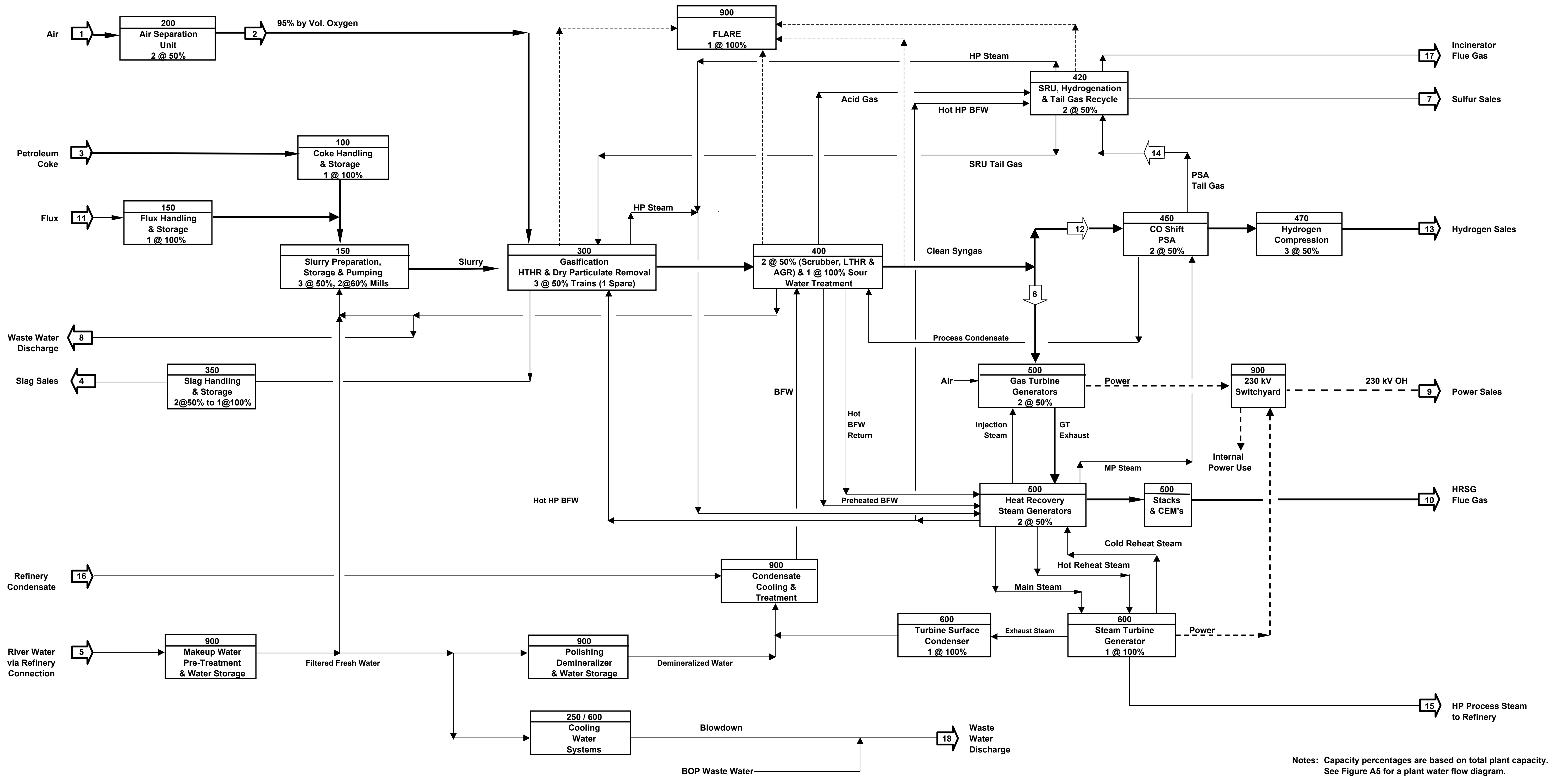
Total Gas Turbine Emissions	
GT/HRSG Stack Exhaust Flow Rate (from 2 trains), lb/hr	7,967,000
GT/HRSG Stack Exhaust Temperature, °F	258
Emissions	
SO_x, ppmvd	3
SO_x as SO_2, lb/hr	50
NO_x, ppmvd (at 15% oxygen, dry basis)	10
NO_x as NO_2, lb/hr	136
CO, ppmvd	10
CO, lbl/hr	79
Incinerator Emissions	
Stack Exhaust Flow Rate, lb/hr	658,800+
Stack Exhaust Temperature, °F	500
Emissions	
SO_x, ppmvd	280
SO_x as SO_2, lb/hr	300
NO_x, ppmvd (at 3% oxygen, dry basis)	40
NO_x as NO_2, lb/hr	31
CO, ppmvd	50
CO, lbl/hr	27
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	8,625,800+
Emissions	
SO_x, ppmvd	22
SO_x as SO_2, lb/hr	350
NO_x, ppmvd	14
NO_x as NO_2, lb/hr	166
CO, ppmvd	15
CO, lbl/hr	106
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	99.4

* Expected emissions performance
\+ Includes PSA tail gas

Figure A4

Detailed Block Flow Diagram of the Next

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.
See Figure A5 for a plant water flow diagram.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coke	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	Flux	Syngas	Hydrogen	Tail Gas	HP Steam	Condensate	Flue Gas	Water			
Flow	25,961	5,954	5,417	195.1	2,611,500	1,016,830	373.4	49,177	474,000	7,966,800	110.6	363,028	80	93.4	980,000	686,000	658,750	504,000			
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Tons/Day	Lb/Hr	MMSCFD	MMSCFD	Lb/Hr	Lb/Hr	Lb/Hr	Lb/Hr			
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	NA	350	1,000	5	700	200	Atmos.	Atmos.			
Temperature - F	70	240	Ambient	180	70	530	332	80	NA	253	NA	530	120	113	750	190	500	71			
HHV Btu/lb	NA	NA	14,848	NA	NA	3,725	NA	NA	NA	NA	NA	3,725	NA	753	NA	NA	NA	NA			
LHV Btu/lb	NA	NA	14,548	NA	NA	3,533	NA	NA	NA	NA	NA	3,533	NA	659	NA	NA	NA	NA			
Energy - MM HHV/hr	NA	NA	6,703	NA	NA	3,788	NA	NA	NA	NA	NA	1,352	1,083	281	NA	NA	NA	NA			
Energy - MM LHV/hr	NA	NA	6,567	NA	NA	3,592	NA	NA	NA	NA	NA	1,282	917	246	NA	NA	NA	NA			
Notes	Dry Basis	5,615 O2	Dry Basis	15%Wtr.	5,223 GPM	To GT	Sales	98 GPM	230 kV			For H2	Sales	373 MLb/hr	Sales	Return		1,008 GPM			

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.3

NEXT OPTIMIZED PETROLEUM COKE IGCC

COPRODUCTION PLANT

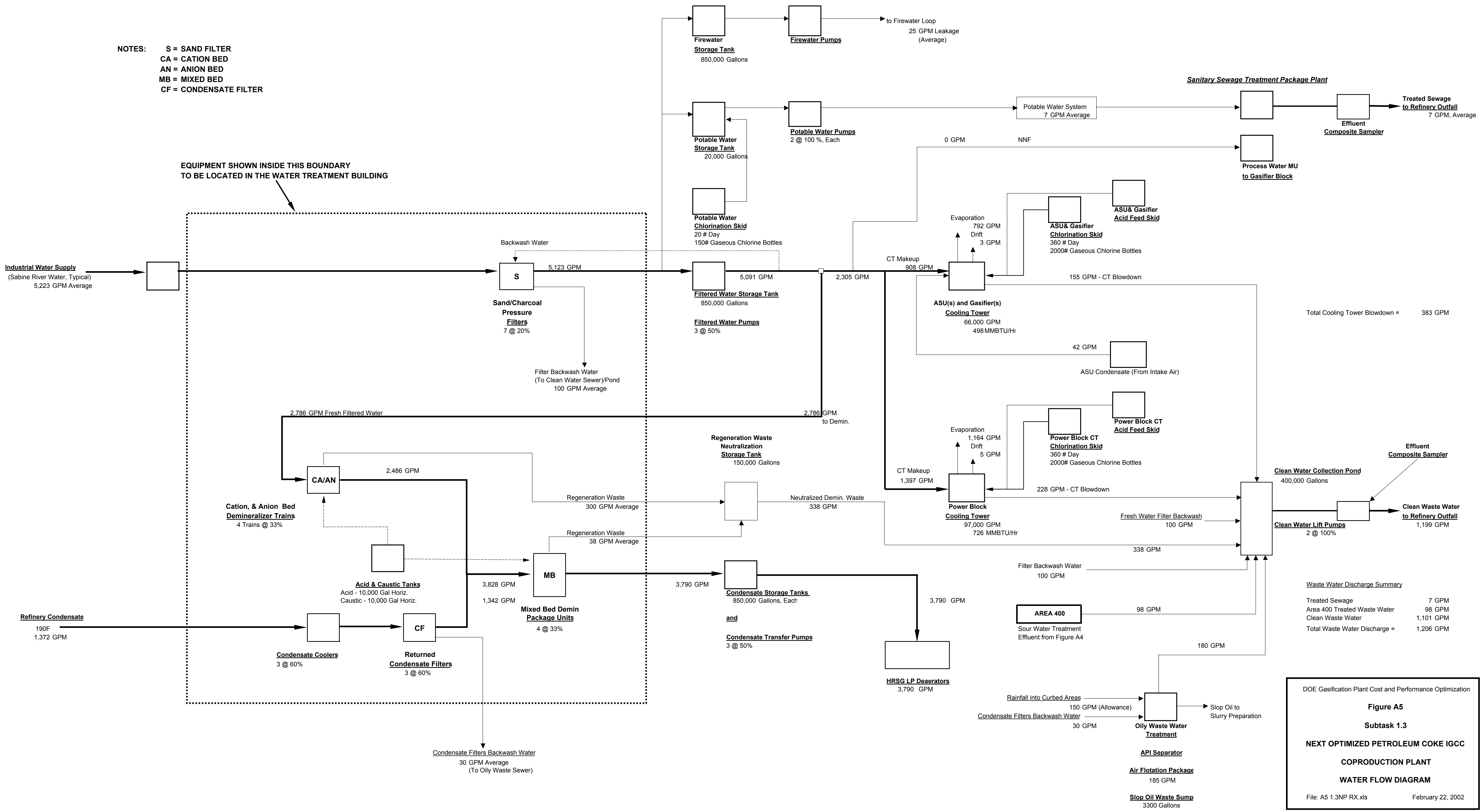
BLOCK FLOW DIAGRAM

File: Fig A4 1.3NP RX.xls February 21, 2002

Figure A5

Overall Water Flow Diagram of the Next

Optimized Petroleum Coke IGCC Coproduction Plant



NOTES: S = SAND FILTER
CA = CATION BED
AN = ANION BED
MB = MIXED BED
CF = CONDENSATE FILTER
EQUIPMENT SHOWN INSIDE THIS BOUNDARY
TO BE LOCATED IN THE WATER TREATMENT BUILDING
Industrial Water Supply
(Sabine River Water, Typical)
5,223 GPM Average
Backwash Water
S
5,123 GPM
Sand/Charcoal
Pressure
Filters
7 @ 20%
Filter Backwash Water
(To Clean Water Sewer)/Pond
100 GPM Average
Firewater
Storage Tank
850,000 Gallons
Firewater Pumps
to Firewater Loop
25 GPM Leakage
(Average)
Potable Water
Storage Tank
20,000 Gallons
Potable Water Pumps
2 @ 100 %, Each
Potable Water System
7 GPM Average
Potable Water
Chlorination Skid
20 # Day
150# Gaseous Chlorine Bottles
5,091 GPM
Filtered Water Storage Tank
850,000 Gallons
Filtered Water Pumps
3 @ 50%
2,305 GPM
0 GPM
NNF
Sanitary Sewage Treatment Package Plant
Treated Sewage
to Refinery Outfall
7 GPM, Average
Effluent
Composite Sampler
Process Water MU
to Gasifier Block
Evaporation
792 GPM
Drift
3 GPM
ASU& Gasifier
Chlorination Skid
360 # Day
2000# Gaseous Chlorine Bottles
ASU& Gasifier
Acid Feed Skid
CT Makeup
908 GPM
155 GPM - CT Blowdown
ASU(s) and Gasifier(s)
Cooling Tower
66,000 GPM
498 MMBTU/Hr
Total Cooling Tower Blowdown = 383 GPM
42 GPM
ASU Condensate (From Intake Air)
2,786 GPM Fresh Filtered Water
2,786 GPM
to Demin.
Evaporation
1,164 GPM
Drift
5 GPM
Power Block CT
Chlorination Skid
360 # Day
2000# Gaseous Chlorine Bottles
Power Block CT
Acid Feed Skid
CT Makeup
1,397 GPM
228 GPM - CT Blowdown
Power Block
Cooling Tower
97,000 GPM
726 MMBTU/Hr
Regeneration Waste
Neutralization
Storage Tank
150,000 Gallons
CA/AN
2,486 GPM
Regeneration Waste
300 GPM Average
Neutralized Demin. Waste
338 GPM
Cation, & Anion Bed
Demineralizer Trains
4 Trains @ 33%
Regeneration Waste
38 GPM Average
Acid & Caustic Tanks
Acid - 10,000 Gal Horiz.
Caustic - 10,000 Gal Horiz.
MB
3,828 GPM
1,342 GPM
Mixed Bed Demin
Package Units
4 @ 33%
3,790 GPM
Condensate Storage Tanks
850,000 Gallons, Each
and
Condensate Transfer Pumps
3 @ 50%
3,790 GPM
HRSG LP Deaerators
3,790 GPM
Refinery Condensate
190F
1,372 GPM
Condensate Coolers
3 @ 60%
CF
Returned
Condensate Filters
3 @ 60%
Condensate Filters Backwash Water
30 GPM Average
(To Oily Waste Sewer)
Clean Water Collection Pond
400,000 Gallons
Effluent
Composite Sampler
Fresh Water Filter Backwash
100 GPM
Clean Water Lift Pumps
2 @ 100%
Clean Waste Water
to Refinery Outfall
1,199 GPM
338 GPM
Filter Backwash Water
100 GPM
AREA 400
98 GPM
Sour Water Treatment
Effluent from Figure A4
180 GPM
Waste Water Discharge Summary
Treated Sewage 7 GPM
Area 400 Treated Waste Water 98 GPM
Clean Waste Water 1,101 GPM
Total Waste Water Discharge = 1,206 GPM
Rainfall into Curbed Areas
150 GPM (Allowance)
Condensate Filters Backwash Water
30 GPM
Oily Waste Water
Treatment
Slop Oil to
Slurry Preparation
API Separator
Air Flotation Package
185 GPM
Slop Oil Waste Sump
3300 Gallons
DOE Gasification Plant Cost and Performance Optimization
Figure A5
Subtask 1.3
NEXT OPTIMIZED PETROLEUM COKE IGCC
COPRODUCTION PLANT
WATER FLOW DIAGRAM
File: A5 1.3NP RX.xls
February 22, 2002

A.5 Major Equipment List

Table D3 lists the major pieces of equipment and systems by process area in the Next Optimized Petroleum Coke IGCC Coproduction Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit and the PSA unit, are not available.

Table A3
Major Equipment of the Next Optimized Petroleum Coke IGCC Coproduction Plant

Fuel Handling – 100
Coke Storage Dome
Reclaim Conveyors
Storage/Feed Bins
Coke Handling Electrical Equipment and Distribution
Electric Hoist
Metal Detector
Magnetic Separator
Flux Silo
Vibrating Feeder
Slurry Preparation – 150
Weigh Belt Feeder
Rod Charger
Rod Mill
Rod Mill Product Tank
Rod Mill Product Tank Agitator
Rod Mill Product Pumps
Recycle Water Storage Tank
Recycle Water Pumps
Slurry Storage Tank
Slurry Storage Tank Agitator
Slurry Recirculation Pumps
Solids Recycle Tank
Solids Recycle Tank Agitator
Solids Recycle Pumps
Rod Mill Lube Oil Pumps
Slurry Feed Pumps (1^{st} Stage)
Slurry Feed Pumps (2^{nd} Stage)
ASU – 200
Air Separation Unit Including:
Main Air Compressor
Air Scrubber
Oxygen Compressor
Cold Box (Main Exchanger)
Oxygen Compressor Expander
Liquid Nitrogen Storage

ASU & Gasifier Area Cooling Water - 250
Cooling Water Circulation Pump
Cooling Tower (S/C)
Gasification - 300
Main Slurry Mixers
Second Stage Mixer
Gasifier Vessel
High Temperature Heat Recovery Unit (HTRU)
Cyclone Separators
Slag Pre-Crushers
Slag Crushers
Reactor Nozzle Cooling Pumps
Crusher Seal Water Pumps
Syngas Desuperheater
Nitrogen Heater
Pressure Reduction Units
Dry Char Filters
Cyclone Solids Pickup Vessel
Filter Solids Pickup Vessel
Slag Handling – 350
Slag Dewatering Bins
Slag Gravity Settler
Slag Water Tank
Slag Water Pumps
Gravity Settler Bottoms Pumps
Slag Recycle Water Tank
Slag Feedwater Quench Pumps
Slag Water Recirculation Pumps
Polymer Pumps
Slag Recycle Water Cooler
LTHR/AGR – 400
Syngas Scrubber Column
Syngas Scrubber Recycle Pumps
Syngas Recycle Compressor
Syngas Recycle Compressor K. O. Drum
Syngas Heater
COS Hydrolysis Unit
Amine Reboiler
Sour Water Condenser
Sour Gas Condensate Condenser
Sour Gas CTW Condenser
Sour Water Level Control Drum
Sour Water Receiver
Sour Gas Knock Out Pot
Sour Water Carbon Filter
MDEA Storage Tank
Lean Amine Pumps
Acid Gas Absorber

MDEA Cross-Exchangers
MDEA CTW Coolers
MDEA Carbon Bed
MDEA Post-Filter
Acid Gas Stripper
Acid Gas Stripper Recirculation Cooler
Acid Gas Stripper Reflux Drum
Acid Gas Stripper Quench Pumps
Acid Gas Stripper Reboiler
Acid Gas Stripper Overhead Filter
Lean MDEA Transfer Pumps
Acid Gas Stripper Knock Out Drum
Acid Gas Stripper Preheater
Amine Reclaim Unit
Condensate Degassing Column
Degassing Column Bottoms Cooler
Sour Water Transfer Pumps
Ammonia Stripper
Ammonia Stripper Bottoms Cooler
Stripped Water Transfer Pumps
Quench Column
Quench Column Bottoms Cooler
Stripped Water Transfer Pumps
Degassing Column Reboiler
Ammonia Stripper Reboiler
Syngas Heater
Syngas Moisturizer
Moisturizer Recirculation Pumps
Sulfur Recovery – 420
Reaction Furnace/Waste Heat Boiler
Condensate Flash Drum
Sulfur Storage Tank
Storage Tank Heaters
Sulfur Pump
Claus First Stage Reactor
Claus First Stage Heater
Claus First Stage Condenser
Claus Second Stage Reactor
Claus Second Stage Heater
Claus Second Stage Condenser
Condensate Level Drum
Hydrogenation Gas Heater
Hydrogenation Reactor
Quench Column
Quench Column Pumps
Quench Column Cooler
Quench Strainer
Quench Filter
Tail Gas Recycle Compressor

Tail Gas Recycle Compressor Intercooler
Tank Vent Blower
Tank Vent Combustion Air Blower
Tank Vent Incinerator/Waste Heat Boiler
Tank Vent Incinerator Stack
CO Shift – 450
ZnO Reactor
HT Shift Reactor
LT Shift Reactor
Gas-gas Exchanger
Steam Generator
Air Cooler
Start-up Fired Heater
PSA – 460
PSA Unit
Hydrogen Compression – 470
Hydrogen Compressors
Gas Turbine / HRSG – 500
Gas Turbine Generator (GTG), GE 7FA+e, Dual Fuel (Gas and Syngas) Industrial turbine set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel skids.
GTG Erection (S/C)
Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, with Integral Deaerator
HRSG Stack (S/C)
HRSG Continuous Emissions Monitoring Equipment
HRSG Feedwater Pumps
HRSG Blowdown Flash Tank
HRSG Atmospheric Flash Tank
HRSG Oxygen Scavenger Chemicals Injection Skid
HRSG pH Control Chemicals Injection Skid
GTG Iso-phase Bus Duct
GTG Synch Breaker
Power Block Auxilary Power XformerS
Steam Turbine Generator & Auxiliaries - 600
Steam Turbine Generator (STG), Reheat, TC2F, complete with lube oil console
Steam Surface Condenser, 316L tubes
Condensate (hotwell) pumps
Circulating Water Pumps
Auxiliary Cooling Water Pumps
Cooling Tower
Balance Of Plant - 900
High Voltage Electrical Switch Yard (S/C)
Common Onsite Electrical and I/C Distribution
Distributed Control System (DCS)
In-Plant Communication System

15KV, 5KV and 600V Switchgear
BOP Electrical Devices
Power Transformers
Motor Control Centers
Makeup Pumps
Substation & Motor Control Center (MCC)
Lighting, Heating & Ventilation
Makeup Water Treatment Storage and Distribution
Water Treatment Building Equipment
Carbon Filters
Cation Demineralizer Skids
Degasifiers
Anion Demineralizer Skids
Demineralizer Polishing Bed Skids
Bulk Acid Tank
Acid Transfer Pumps
Demineralizer - Acid Day Tank Skid
Bulk Caustic Tank Skid
Caustic Transfer Pumps
Demineralizer - Caustic Day Tank Skid
Firewater Pump Skids
Waste Water Collection and Treatment
Oily Waste - API Separator
Oily Waste - Dissolved Air Flotation
Oily Waste Storage Tank
Sanitary Sewage Treatment Plant
Wastewater Storage Tanks
Monitoring Equipment
Common Mechanical Systems
Shop Fabricated Tanks
Miscellaneous Horizontal Pumps
Auxiliary Boiler
Safety Shower System
Flare
Flare Knock Out Drum
Flare Knock Out Drum Pumps
Chemical Feed Pumps
Chemical Storage Tanks
Chemical Storage Equipment
Laboratory Equipment

The petroleum coke IGCC plant is assumed to be located adjacent to a petroleum refinery, and thus, can share some infrastructure with the refinery. It is assumed that

1. The refinery delivers the coke to the coke storage dome.
2. The IGCC plant gets the river water from the refinery water intake system.
3. The refinery processes the process waste water from the IGCC plant through the refinery waste water treatment facilities.

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.3 Next Plant scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 42 months which includes three months of performance testing before full commercial operation. This is the same project schedule as the other Subtask 1.3 plants. Notice to proceed is based on a confirmed Gulf Coast plant site and availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor and air separation unit.

The project construction schedule of the Next Optimized Petroleum Coke IGCC Coproduction Plant was developed by examining that of the Wabash River Repowering Project and correcting for several problems that were encountered during construction. Furthermore, construction experts were included in the Value Improving Practices team that developed the plant layout so that both ease of construction and maintenance were considered.

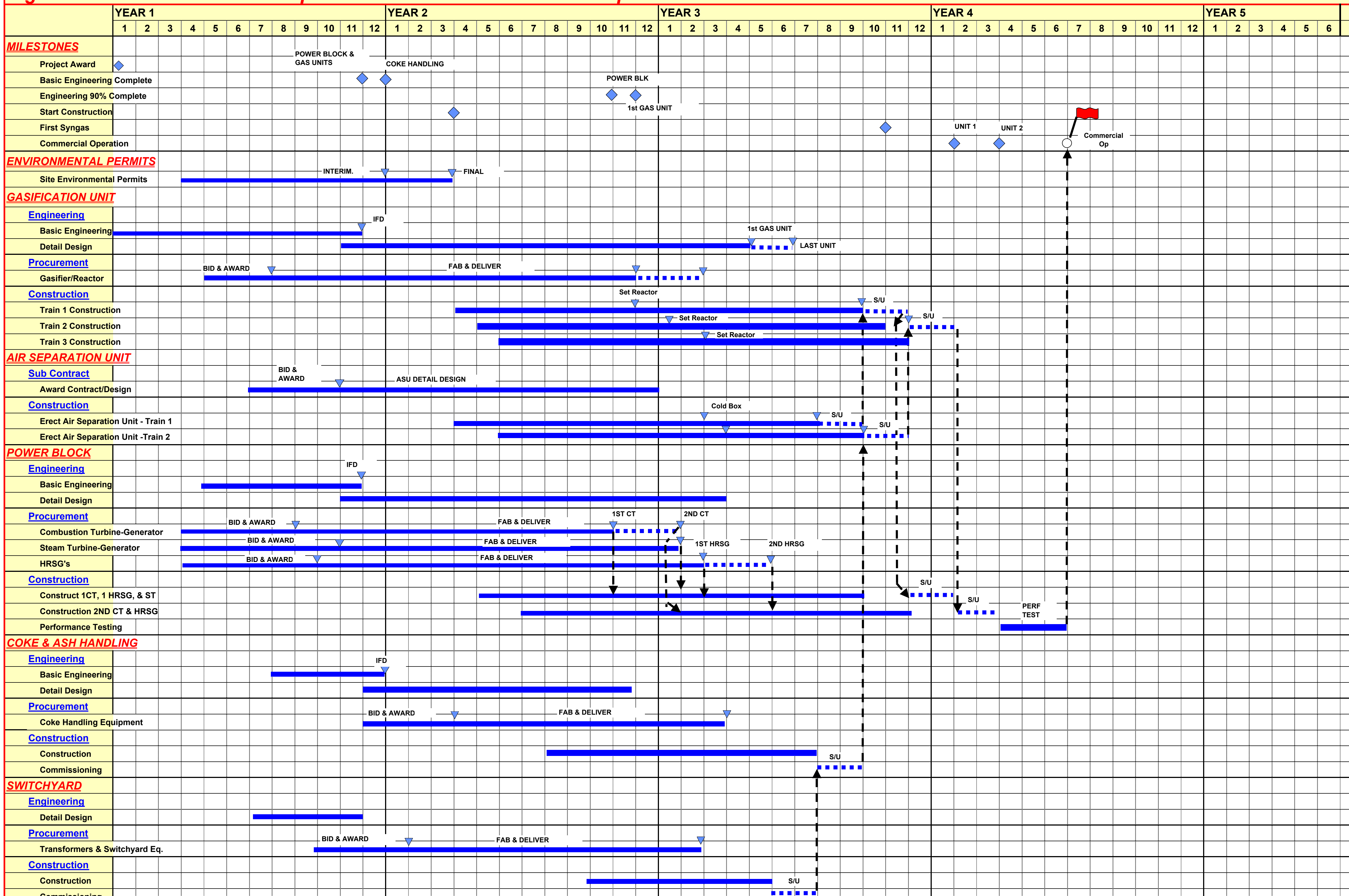
The milestone construction schedule for the major process blocks of the Next Optimized Petroleum Coke IGCC Coproduction Plant is shown in Figure A6.

Figure A6

Milestone Construction Schedule for the Next

Optimized Petroleum Coke IGCC Coproduction Plant

Figure A6 Subtask 1.3 - Next Optimized Petroleum Coke IGCC Coproduction Plant



BY	DATE	REV.
TM	3/26/01	D
TM	9/11/00	C
SO	6/28/00	B
RHS	6/23/00	A

Bechtel
Houston, Texas

US DEPARTMENT OF ENERGY
Gasification Plant Cost & Performance Optimization
Subtask 1.3 Optimized Petcoke IGCC
Milestone Schedule

A.6.2 Capital Cost Summary

A.6.2.1. General

The following table illustrates the work breakdown structure (WBS) for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant and the source of the cost information for each of the areas. The WBS for this case is the same as that which was used for Subtask 1.2 and the other Subtask 1.3 plants.

WBS	Description	Subtask 1.3
100	Solid Fuel Handling	Bechtel Engineering to provide scope and estimate
150	Slurry Preparation	Adjusted Wabash River and selected quotes
200	Air Separation Unit	Praxair Quote
300	Gasification	Adjusted Wabash River and selected quotes
350	Slag Handling	Adjusted Wabash River
400	Sulfur Removal	Adjusted Wabash River and selected quotes
420	Sulfur Recovery	Adjusted Wabash River and selected quotes
450	CO Shift	Bechtel Engineering to provide scope and estimate
460	PSA	Bechtel Engineering to provide scope and UOP quote
470	Hydrogen Compression	Bechtel Engineering to provide scope and compressor quotes
500	GT/HRSG	Based on Bechtel's Powerline™ design and cost information
600	Steam Turbine & Auxiliary Equipment	Based on Bechtel's Powerline™ design and cost information
900	Balance Of Plant	
	High Voltage Switchyard	Bechtel Engineering to provide scope and estimate
	Makeup Water Intake	Bechtel Engineering to provide scope and estimate
	Makeup Water Treatment System	Bechtel Engineering to provide scope and estimate
	Waste Water Collection System	Bechtel Engineering to provide scope and estimate
	Waste Water Discharge	Discharged to refinery discharge system
	Solids Discharge	Used catalyst to landfill
	Piping	By Comet model as calibrated to Wabash River
	Concrete, Steel and Architecture	Wabash River / PSI adjusted for technical basis
	Common Electrical and I&C Systems	Based on Wabash River adjusted for technical basis

Vendor quotes were obtained for most of the new and high price equipment in Subtask 1.3. The power block cost estimate is based on an estimated current General Electric price for the 7FA+e gas turbines and Bechtel Powerline™ cost for similar sized power plant currently under construction on the Gulf Coast. Thus, compared to Subtask 1.2, a much smaller part of the plant costs were estimated based on the Wabash River facility and adjusted for inflation. Gulf Coast non-union mid-year 2000 labor rates were used, the same labor rate as was used for Subtask 1.2 so that this cost estimate is comparable.

This cost estimate is an "overnight" mid-year 2000 cost estimate based on market pricing. There is no forward escalation. As such, it reflects any aberrations in equipment costs based on current market conditions. For example, there is a large demand and backlog for gas turbines so that the current price seems high based on historical data.

Major Equipment

Major equipment from Subtasks 1.1 and 1.2 was loaded into a data base and modified to reflect the scope of the Subtask 1.3 next plant. Modifications include changes in equipment duty (as a result of both capacity changes and the Design-to-Capacity VIP), quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

The Design-to-Capacity and Classes of Plant Quality Value Improving Practices were considered in sizing the equipment for the Subtask 1.3 next plant. Because the composition of delayed petroleum coke is less variable than the range of coals that were considered in the design of the Wabash River Repowering Project, less overdesign was needed in many areas to provide feedstock flexibility. Furthermore, some equipment was redesigned to reflect current engineering design practices.

Bulk Materials

Wabash River Repowering Project bulk commodity quantity estimates for steel, concrete, and piping were used as the basis, and then the quantities were adjusted to reflect the scope and site plan for this subtask. Current pricing was used to estimate the costs for the bulk material items.

Subcontracts

Supply and install subcontract pricing was estimated for:

By Budget Quote

- Coke Handling
- Field Erected Tanks
- Air Separation Unit
- Cooling Tower (except basin)

By Unit Pricing

- Buildings including interior finish, HVAC, and Furnishings
- Fire Protection Systems
- Site Development
- Rail Spur

From the Wabash River Facility

- Painting and Insulation
- 230 KV Switchyead
- Gasifier Refractory
- Start-up Services; i.e., flushes and steam blows

Construction

Labor is based on mid-year 2000 Gulf Coast merit shop rates and historic productivity factors. Union labor is used for refractory installation.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.3 next plant. Power block costs are based on Bechtel's Powerline™ design and current cost information.

Material Take-off

Subtask 1.1 quantities were used as the basis and adjusted to reflect the scope and site plan for Subtask 1.3 next plant, as was done for Subtask 1.2. Modifications were made, as necessary. Concrete, steel and instrumentation were adjusted on an area by area basis reflecting the increased numbers of process trains. The basis for piping adjustment was developed from quantities generated by the COMET model. Electrical quantities were manually adjusted for this subtask.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Design criteria basis are the codes, standards, laws and regulations to be compliant with U. S. and local codes for the designated region typical for U. S. installations and for the designated location of the plant.
- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000 Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- For new and highly priced equipment, current vendor quotes were obtained to reflect current market pricing.
- Site Conditions:
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Tie-ins to the adjoining refinery are located on the north and east sides of the site
  - Coke is provided at the battery limits on the north side of the site
- Cost includes only areas within the site plan
- Critical spares are included; e.g., proprietary items, one-of-a-kind items, and long lead time items. Normal warehouse, operational, and commissioning/start-up spares are excluded.
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)

- The following costs are excluded:
  - Contingency and risks
  - Cost of permits
  - Taxes
  - Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
  - Facilities external to the site in support of the plant
  - Licensing fees
  - Agent fees
  - Initial fill of chemicals

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant.

Table A4

Capital Cost Summary of the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant[2]

Plant Area	Direct Field Material	Direct Field Labor	Other Costs	Total
Solids Handling	4,300,000	2,700,000	1,012,000	8,012,000
Air Separation Unit	65,172,000	41,249,000	826,000	107,246,000
Gasification	195,381,000	66,912,000	50,298,000	312,591,000
Hydrogen Production	31,939,000	4,919,000	6,073,000	42,931,000
Power Block	200,286,000	22,333,000	14,425,000	237,045,000
Balance Of Plant	50,000,000	26,027,000	3,393,000	79,420,000
Total	547,078,000	164,140,000	76,027,000	787,246,000

Note: Because of rounding, some columns may not add to the total that is shown.

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±11%. The level of accuracy reflects a high degree of confidence based on the large number of vendor quotes that were obtained and that the power block costs are based on a current similar Gulf Coast power project. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

[2] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Appendix D

Subtask 1.3 Next Plant (Appendix B)

Financial Model Analysis Input

Subtask 1.3 Next Plant (Appendix B)

Financial Analysis Model Input

Bechtel Technology and Consulting (now Nexant) developed the DCF financial model as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task.[1] This model performs a discounted cash flow financial analysis to calculate investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data directly related to the specific plant as follows.

Data on the Plant Input Sheet
- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table B1 contains the data that are entered on the Plant Input Sheet for Subtask 1.2 and for the four Subtask 1.3 cases.

The Scenario Input Sheet primarily contains data that are related to the general economic environment that is associated with the plant. In addition, it also contains some data that are plant related. The data on the Scenario Input Sheet are shown below.

Data on the Scenario Input Sheet
- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Start up information

Table B2 contains the base case data that are entered on the Scenario Input Sheet for Subtask 1.2 and for the four Subtask 1.3 cases.

[1] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Table B1
Plant Input Sheet Data for Subtasks 1.2 and 1.3

Project Summary Data					
Project Name / Description	Subtask 1.2 on 1.3 Basis	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Case	Subtask 1.3 Next Plant
Project Location	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast
Project Type/Structure	BOO	BOO	BOO	BOO	BOO
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs	Multiple Outputs	Multiple Outputs	Multiple Outputs	Multiple Outputs
Fuel Type **(Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Petroleum Coke	Petroleum Coke	Petroleum Coke	Petroleum Coke	Petroleum Coke
Plant Input/Output Flowrates - Daily Average Basis (Calendar Day)					
Syngas Capacity (MMscf/day) - Optional					
Gross Electric Power Capacity (MW) - Optional	487	570	570	570	584.3
Net Electric Power Capacity (MW)	374.3	430.0	425.4	436.4	448.4
Steam Capacity (Tons/hr)	486.1	479.3	473.1	487.0	487.3
Hydrogen Capacity (MMscf/day)	78.8	77.5	76.5	78.7	78.8
Carbon Monoxide Capacity (MMscf/day) - PSA Tail Gas (Low Btu Fuel Gas)	99.8	0.0	0.0	0.0	0.0
Elemental Sulfur (Tons/day)	324.1	296.8	273.6	331.5	333.8
Slag Ash (Tons/day)	167.8	155.3	143.1	173.4	174.4
Fuel (Tons/day)	4,635.3	4,309.8	3,973.1	4,814.2	4,842.3
Chemicals - **Natural Gas (Mscf/day) - INPUT**	-10,099	-20,000	-26,977	-9,303	-9,059
Environmental Credit (Tons/day)	0	0	0	0	0
Other (Tons/day) - Flux **- INPUT**	-94.5	-88.0	-81.1	-98.8	-98.9
Operating Hours per Year	8,760	8,760	8,760	8,760	8,760
Guaranteed Availability (percentage)	100.0%	100.0%	100.0%	100.0%	100.0%
Enter One of the Following Items Depending on Project Type:					
Heat Rate (Btu/kWh) based on HHV - Required for power projects					
Annual Fuel Consumption (in MMcf or Thousand Tons) - Required for non-power projects	1,691.9	1,573.1	1,450.2	1,757.2	1,767.4
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)					
EPC (in thousand dollars)	993,200	764,040	746,040	812,569	787,246
Owner's Contingency (% of EPC Costs)	5%	5%	5%	5%	5.0%
Development Fee (% of EPC Costs)	1.23%	1.23%	1.23%	1.23%	1.23%
Start-up (% of EPC Costs)	1.50%	1.50%	1.50%	1.50%	1.50%
Owner's Cost (in thousand dollars) - Land	$250	$200	$200	$200	$200
Additional Capital Cost - Spares	$11,000	$11,000	$11,000	$11,000	$11,000
Additional Cost #1 - Duties, Taxes, Insurance, etc.	$1,650	$1,650	$1,650	$1,650	$1,650
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent -To be verified during project development. (in thousand dollars)	$49,660	$38,202	$37,302	$40,628	$39,362
Operating Costs and Expenses					
Variable O&M (% of EPC Cost) - **HIGHLY CONFIDENTIAL**					
Fixed O&M Cost (% of EPC Cost) - Staffing - **HIGHLY CONFIDENTIAL**					
Additional Comments: When the average daily input and output flow rates, as calculated by the availability analysis, are supplied, the guaranteed plant availability should be set to 100.0%.	Subtask 1.2 - Non-optimized Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Optimized Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Minimum Cost Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Spare Solids Processing Petroleum Coke IGCC Coproduction Plant	Subtask 1.3 - Next Plant - 9/20/01

Table B2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3
(Page 1 of 4)

Project Name / Description	Subtask 1.2 on 1.3 Basis	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Solids Processing Case	Subtask 1.3 Next Plant
Project Location	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast	US Gulf Coast
Project Type/Structure	BOO	BOO	BOO	BOO	BOO

Capital Structure					
Percentage Debt	80%	80%	80%	80%	80%
Percentage Equity	20%	20%	20%	20%	20%
Total Debt Amount (in thousand dollars) -**CALCULATED**	---	---	---	---	---

Project Debt Terms					
Loan 1: Senior Debt					
% of Total Project Debt **(total for Loans 1,2, and 3 must = 100%)**	100%	100%	100%	100%	100%
Loan Amount (in thousand dollars) -**CALCULATED**	---	---	---	---	---
Interest Rate	10%	10%	10%	10%	10%
Financing Fee	3%	3%	3%	3%	3%
Repayment Term (in Years)	15	15	15	15	15
Grace Period on Principal Repayment	0	0	0	0	0
First Year of Principal Repayment	2003	2003	2003	2003	2003
Loan 2: Subordinated Debt					
% of Total Project Debt	0%	0%	0%	0%	0%
Loan Amount (in thousand dollars) -**CALCULATED**	0	0	0	0	0
Interest Rate	8%	8%	8%	8%	8%
Financing Fee	3%	3%	3%	3%	3%
Repayment Term (in Years)	15	15	15	15	15
Grace Period on Principal Repayment	1	1	1	1	1
First Year of Principal Repayment	2004	2004	2004	2004	2004
Loan 3: Subordinated Debt					
% of Total Project Debt	0%	0%	0%	0%	0%
Loan Amount (in thousand dollars) -**CALCULATED**	0	0	0	0	0
Interest Rate	7%	7%	7%	7%	7%
Financing Fee	3%	3%	3%	3%	3%
Repayment Term (in Years)	10	10	10	10	10
Grace Period on Principal Repayment	1	1	1	1	1
First Year of Principal Repayment	2004	2004	2004	2004	2004

Loan Covenant Assumptions					
Interest Rate for Debt Reserve Fund (DRF)	5%	5%	5%	5%	5%
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	Yes	Yes	Yes	Yes	Yes
Percentage of Total Debt Service used as DRF	20%	20%	20%	20%	20%

Depreciation					
Construction (Years)	7	7	7	7	7
Financing (Years)	7	7	7	7	7

Working Capital					
Days Receivable	30	30	30	30	30
Days Payable	30	30	30	30	30
Annual Operating Cash (in thousand dollars)	50	100	100	100	100
Initial Working Capital (% of first year revenues)	0%	0%	0%	0%	0%

ECONOMIC ASSUMPTIONS

Cash Flow Analysis Period					
Plant Economic Life/Concession Length (in Years)	20	20	20	20	20
Discount Rate	12%	12%	12%	12%	12%

Table B2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3

Escalation Factors					
Project Output/Tariff					
Syngas	1.7%	1.7%	1.7%	1.7%	1.7%
Electricity: Capacity Payment	1.7%	1.7%	1.7%	1.7%	1.7%
Electricity: Energy Payment	1.7%	1.7%	1.7%	1.7%	1.7%
Steam	3.1%	3.1%	3.1%	3.1%	3.1%
Hydrogen	3.1%	3.1%	3.1%	3.1%	3.1%
Carbon Monoxide	1.7%	1.7%	1.7%	1.7%	1.7%
Elemental Sulfur	0.0%	0.0%	0.0%	0.0%	0.0%
Slag Ash	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel (IGCC output)	0.0%	0.0%	0.0%	0.0%	0.0%
Chemicals - **Natural Gas**	3.9%	3.9%	3.9%	3.9%	3.9%
Environmental Credit	1.7%	1.7%	1.7%	1.7%	1.7%
Other **- Flux**	1.7%	1.7%	1.7%	1.7%	1.7%
Fuel/Feedstock					
Gas	3.9%	3.9%	3.9%	3.9%	3.9%
Coal	1.2%	1.2%	1.2%	1.2%	1.2%
Petroleum Coke	0.0%	0.0%	0.0%	0.0%	0.0%
Other/Waste	2.3%	2.3%	2.3%	2.3%	2.3%
Operating Expenses and Construction Items					
Variable O&M	2.3%	2.3%	2.3%	2.3%	2.3%
Fixed O&M	2.3%	2.3%	2.3%	2.3%	2.3%
Other Non-fuel Expenses	2.3%	2.3%	2.3%	2.3%	2.3%

Tax Assumptions					
Tax Holiday (in Years)	0	0	0	0	0
Income Tax Rate	40%	40%	40%	40%	40%
Subsidized Tax Rate (used as investment incentive)	0%	0%	0%	0%	0%
Length of Subsidized Tax Period (in Years)	0	0	0	0	0

FUEL/FEEDSTOCK ASSUMPTIONS

Fuel Price					
Gas ($/Mcf)	2.60	2.60	2.60	2.60	2.60
Coal ($/Ton)	22.0	22.0	22.0	22.0	22.0
Petroleum Coke ($/Ton)	0.00	0.00	0.00	0.00	0.00
Other/Waste ($/Ton)	14.00	14.00	14.00	14.00	14.00

Heating Value Assumptions					
HHV of Natural Gas (Btu/cf)	1,000	1,000	1,000	1,000	1,000
HHV of Coal (Btu/kg)	23,850	23,850	23,850	23,850	23,850
HHV of Petroleum Coke (Btu/kg), Dry basis	32,735	32,735	32,735	32,735	32,735
HHV of Other/Waste (Btu/kg)	0	0	0	0	0

TARIFF ASSUMPTIONS

INITIAL TARIFF LEVEL (In Dollars in the first year of construction)					
Syngas ($/Mcf)	$0	$0	$0	$0	$0
Capacity Payment (Thousand $/MW/Year)	$0	$0	$0	$0	$0
Electricity Payment ($/MWh)	$27.00	$27.00	$27.00	$27.00	$27.00
Steam ($/Ton)	$5.60	$5.60	$5.60	$5.60	$5.60
Hydrogen ($/Mcf)	$1.30	$1.30	$1.30	$1.30	$1.30
Carbon Monoxide ($/Mcf)	$0.2274	$0.2274	$0.2274	$0.2274	$0.2274
Elemental Sulfur ($/Ton)	$30.00	$30.00	$30.00	$30.00	$30.00
Slag Ash ($/Ton)	$0	$0	$0	$0	$0
Fuel ($/Ton)	$0	$0	$0	$0	$0
Chemicals **- Natural Gas ($/Mscf)**	$2.60	$2.60	$2.60	$2.60	$2.60
Environmental Credit ($/Ton)	$0	$0	$0	$0	$0
Other ($/Ton) - **Flux**	$5.00	$5.00	$5.00	$5.00	$5.00

CONSTRUCTION ASSUMPTIONS

Construction Schedule					
Construction Start Date	1/1/1999	7/1/1999	7/1/1999	7/1/1999	7/1/1999
Construction Period (in months) - Maximum of 48	48	42	42	42	42
Plant Start-up Date *(must start on January 1)*	1/1/2003	1/1/2003	1/1/2003	1/1/2003	1/1/2003

Table B2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3

Percentage Breakout of Cost over Construction Period (each category must total 100%)					
Year 1					
EPC Costs - See Note 1.	14.655%	9.770%	9.770%	9.770%	9.770%
Initial Working Capital	0%	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%	0%
Development Fee	0%	0%	0%	0%	0%
Start-up Costs	0%	0%	0%	0%	0%
Initial Debt Reserve Fund	0%	0%	0%	0%	0%
Owner's Cost - Land	70%	70%	70%	70%	70%
Additional Capital Costs - Spares	0%	0%	0%	0%	0%
Financing Fee	0%	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%	0%	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	14.655%	9.770%	9.770%	9.770%	9.770%
Year 2					
EPC Costs - See Note 1.	35%	35%	35%	35%	35%
Initial Working Capital	0%	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%	0%
Development Fee	100%	100%	100%	100%	100%
Start-up Costs	0%	0%	0%	0%	0%
Initial Debt Reserve Fund	0%	0%	0%	0%	0%
Owner's Cost - Land	30%	30%	30%	30%	30%
Additional Capital Costs - Spares	0%	0%	0%	0%	0%
Financing Fee	100%	100%	100%	100%	100%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%	50%	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	35%	35%	35%	35%	35%
Year 3					
EPC Costs - See Note 1.	30.69%	30.69%	30.69%	30.69%	30.69%
Initial Working Capital	0%	0%	0%	0%	0%
Owner's Contingency	0%	0%	0%	0%	0%
Development Fee	0%	0%	0%	0%	0%
Start-up Costs	30%	30%	30%	30%	30%
Initial Debt Reserve Fund	0%	0%	0%	0%	0%
Owner's Cost - Land	0%	0%	0%	0%	0%
Additional Capital Costs - Spares	0%	0%	0%	0%	0%
Financing Fee	0%	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%	50%	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	30.69%	30.69%	30.69%	30.69%	30.69%
Year 4					
EPC Costs - See Note 1.	20.46%	26.16%	26.16%	26.16%	26.16%
Initial Working Capital	100%	100%	100%	100%	100%
Owner's Contingency	100%	100%	100%	100%	100%
Development Fee	0%	0%	0%	0%	0%
Start-up Costs	70%	70%	70%	70%	70%
Initial Debt Reserve Fund	100%	100%	100%	100%	100%
Owner's Cost - Land	0%	0%	0%	0%	0%
Additional Capital Costs - Spares	100%	100%	100%	100%	100%
Financing Fee	0%	0%	0%	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%	0%	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	20.46%	26.16%	26.16%	26.16%	26.16%

Table B2
Scenario Input Sheet Data for Subtasks 1.2 and 1.3

Plant Ramp-up Option (Yes or No)	Yes	Yes	Yes	Yes	Yes

Start-Up Operations Assumptions (% of Full Capacity)					
Year 1, First Quarter	25.0%	25.0%	25.0%	25.0%	25.0%
Year 1, Second Quarter	50.0%	50.0%	50.0%	50.0%	50.0%
Year 1, Third Quarter	75.0%	75.0%	75.0%	75.0%	75.0%
Year 1, Fourth Quarter	90.0%	90.0%	90.0%	90.0%	90.0%
Year 1 Average Capacity %	60.0%	60.0%	60.0%	60.0%	60.0%
Year 2, First Quarter	100.0%	100.0%	100.0%	100.0%	100.0%
Year 2, Second Quarter	100.0%	100.0%	100.0%	100.0%	100.0%
Year 2, Third Quarter	100.0%	100.0%	100.0%	100.0%	100.0%
Year 2, Fourth Quarter	100.0%	100.0%	100.0%	100.0%	100.0%
Year 2 Average Capacity %	100.0%	100.0%	100.0%	100.0%	100.0%

CONVERSION FACTORS	
kJ to Btu	0.94783
Btu to kWh	3,413
kg to English Ton	1,016
kW per MW	1,000
kJ/kWh	3,600
Gallons Equivalent to 1 Barrel of Crude Oil	42
Cubic Feet to Cubic Meter	0.02832
Months per Year	12
Hours per Day	24
10^6 (for conversion purposes)	1,000,000
Hours per year	8,760

Note 1. The total is greater than 100% to account for inflation during construction.

Appendix E - Subtask 1.4

Optimized Coal to Power IGCC Plant

Subtask 1.4

Optimized Coal to Power IGCC Plant

The objective of Subtask 1.4 is to develop a design and installed capital cost estimate for a future, highly optimized coal to power IGCC plant, which incorporates the Value Improving Practices (VIP) results from Subtask 1.3 and the next generation of gasification technology enhancements for the production of power from coal.

Subtask 1.3 developed a design and installed capital cost estimate for an optimized Petroleum Coke IGCC Coproduction Plant that is located adjacent to a Gulf Coast petroleum refinery and coproduces hydrogen and steam for the refinery. The Wabash River Repowering Project provided the basic design and cost information for Subtask 1.3. Subtask 1.5 developed designs for single-train coal and coke fueled IGCC power plants based on the Subtask 1.3 design. Subtask 1.4 built upon the results of Subtask 1.3 to develop the future Subtask 1.4 Optimized Coal to Power IGCC Plant located at a generic Mid-West site that will use an advanced “G/H-class” combustion turbine.

Design Objectives

The design objectives of this study were to develop a highly integrated, optimized IGCC coal powered power plant using Global Energy’s advanced gasifier and a future “G/H-class” combustion turbine that is expected to be commercially available for syngas firing near the end of this decade. The Air Separation Unit (ASU) will be integrated with the gas turbine to maximize thermal efficiency. Design alternatives were evaluated based on present day costs and projected inflation/escalation rates. The end result of this study should be a coal-based, base-loaded power plant that will have a 12% return on investment and be economically competitive with power production from natural gas under the current economic scenario. Appendix B contains the basic economic parameters used in this study.

Plant Description

The Subtask 1.4 Optimized Coal to Power IGCC Plant is a large single-train IGCC power plant designed to produce 416.5 MW of electric power from 3,007 TPD of dry Illinois No. 6 coal. It also produces 77 TPD of sulfur and 462 TPD of slag.[1] Figure A4 of Appendix A is a detailed block flow diagram of the plant showing the major stream flow rates. The plant satisfies all applicable environmental laws. Sulfur removal is over 99.5%. No process water is discharged. The plant occupies about 40 acres.

The Air Separation Unit (ASU) produces about 2,294 TPD of 95% oxygen. It is integrated with the combustion gas turbine. Compressed air is withdrawn from the compression side of the gas turbine, cooled, and sent to the ASU. High-pressure nitrogen is returned to the gas turbine for use as a diluent for NOx control. The nitrogen is heated by heat exchange with the compressed air from the gas turbine going to the ASU.

[1] See Appendix A for the coal properties and a detailed description of the plant.

The gasifier is Global Energy's advanced two-stage gasifier which employs a slurry feed vaporization scheme. Char and unreacted coal particles that leave the gasifier in the syngas are collected downstream and recycled back to the first stage of the gasifier. The slurry feed goes to the second stage and comes in contact with the hot syngas leaving the first stage; thus evaporating the slurry water (slurry feed vaporization). Particulates are removed from the syngas in a two-step system down stream of the gasifier. First, a hot cyclone removes over 90% of the particulates, and the remainder is removed by an advanced dry char filtration system. The remainder of the gasification plant is similar to the Subtask 1.5 coal plant.

The combustion turbine is an advanced state-of-the-art "G/H-class" gas turbine that will produce 300.1 MW on syngas and is expected to be commercially available for syngas firing near the end of the decade. The heat recovery steam generation (HRSG)/steam turbine system downstream of the gas turbine produces an additional 164.1 MW of power. The internal power consumption of the plant is about 47.7 MW leaving 416.5 MW of power for export.

The advanced design, economies of scale (attributable to the use of the larger "G/H-class" gas turbine), and the Value Improving Practices (VIP) ideas developed as part of this study are the reasons that this plant is larger, more efficient, and less costly than the Subtask 1.1 Wabash River Greenfield Plant.

Table 1 shows the major design parameters for the Subtask 1.4 Optimized Coal to Power IGCC Plant and compares them to two other single-train IGCC coal power plants: the Subtask 1.1 Wabash River Greenfield Plant, and the current day Subtask 1.5 IGCC Coal Power Plant. The Subtask 1.5 IGCC Coal Power Plant is an optimized design that could be built today with the GE 7FA+e combustion turbine. The Subtask 1.4 optimized design uses an advanced "G/H-class" gas turbine that is larger, more efficient, and is expected to be commercially available for syngas firing near the end of this decade. The Subtask 1.4 optimized design has a higher design thermal efficiency of 44.5% compared to the 38.3% thermal efficiency of the Wabash River Greenfield plant. It produces 54.7% more power (416.5 MW vs. 269.3 MW) from only 33.1% more coal (3,007 TPD vs. 2,259 TPD of dry coal). It also requires less oxygen per ton of coal. The design oxygen consumption of the Subtask 1.4 plant is 0.76 tons of oxygen (95%)/ton of dry coal whereas the Wabash River Greenfield plant design consumes 0.94 tons of oxygen (95%)/ton of dry coal.

Table 2 presents a comparison of this study with a previous study by Falsetti et al. using an "G/H-class" combustion turbine for 50 Hz applications.[2] The Subtask 1.4 design produces about 100 MW less power than the Falsetti cases. However, from 76% of the fuel, the Subtask 1.4 plant produces about 78% of the power output of the 9H_RO_C case. Consequently it has a higher thermal efficiency (+0.7% on a HHV basis and +1.0% on a LHV basis). Furthermore, the air separation unit is 60% smaller. In addition, the expected emissions (on a unit of net power output) basis are significantly lower.

The current day Subtask 1.5 IGCC Coal Power Plant is an intermediate step between the Subtask 1.1 Wabash River Greenfield Plant and the Subtask 1.4 plant. It contains many of the features implemented in the Subtask 1.4 plant, but it uses the presently available GE 7FA+e combustion turbine which is smaller and a commercially proven design. In addition, it uses a less efficient particulate removal system consisting of a cyclone followed by a wet particulate scrubber to clean the syngas. The Subtask 1.5 plant processes 2,335 TPD of dry coal to produce 284.6 MW of export power at a thermal efficiency of 39.1%.

[2] Falsetti, J. S. et al, "From Coal or Oil to 550 MWe via 9H IGCC," Gasification Technologies Conference, San Francisco, Oct. 9-11,2000.

The emissions performance of the Subtask 1.4 optimized plant also is significantly improved over the Wabash River Greenfield plant and the Subtask 1.5 plant. The Subtask 1.4 plant contains a reverse osmosis unit which recycles the product water so that no process water is discharged compared to the Wabash River Greenfield plant that discharges 120 gpm of process water and the Subtask 1.5 plant which discharges 72 gpm of process water. All three plants discharge clear water from the balance of plant facilities consisting of blowdown from the cooling towers and discharge from the fresh water purification facilities.

The SO_2, CO and NOx emissions from the Subtask 1.4 design are significantly less on a per unit of net power production that the Greenfield Plant as shown near the bottom of Table 1. The large reduction in SO_2 emissions is a result of using a scrubber system on the tank vent vapors to remove the sulfur from the vent gases before they are sent to the incinerator. Table 3 shows that the amount of SO_2 leaving in the incinerator flue gas is reduced from 290 to 11.5 lb/hr. Thus, because of this scrubber system, the sulfur removal has increased by 3% from 96.7% to 99.7%.

The CO and NOx emission reductions are a result of using the advanced “G/H-class” combustion turbine with moisturized nitrogen diluent instead of the more conventional GE 7FA and 7FA+e turbines with only steam diluent. However, the Subtask 1.4 NOx emissions level in terms of lb of NOx/MW-hr is not as low as that of the Subtask 1.5 plant because of the diluent used for NOx control in the combustion turbine. The Subtask 1.4 plant uses nitrogen, and the Subtask 1.5 plant uses steam as the diluent. For the Subtask 1.4 plant, the calculated NOx emissions are 10 ppm NOx in the turbine outlet when measured at a 15% oxygen concentration on a dry basis as that of the GE 7FA+e turbine. Because steam was added to the Subtask 1.5 plant, the diluent essentially was omitted when calculating flow rate of the outlet gas stream. This is not the case in the Subtask 1.4 design, which uses a nitrogen diluent, causing it to have a significantly larger dry gas flow rate, and consequently, higher calculated NOx emissions.

Value Improving Practices

As part of Subtask 1.3, which developed an optimized petroleum coke IGCC coproduction plant, a Value Improving Workshop (VIP) was held which developed numerous ideas for improving the design of the petroleum coke IGCC plant. Some of these ideas were applicable only to processing coke, some were applicable only to processing coal, and many were applicable to processing either feedstock. Those VIP items, which were applicable to coal processing, were applied in developing the design for the Subtask 1.4 Optimized Coal to Power IGCC Plant. Table 4 lists the major VIP items that were used. Most of these VIP improvements also were included in the current day Subtask 1.5 IGCC Coal Power Plant.

Cost Estimate

The future Subtask 1.4 Optimized Coal to Power IGCC Plant is expected to cost 465 million mid-year 2000 dollars or about 1,115 $/KW.[3] Table A4 of Appendix A provides a breakdown of the installed cost by plant section. This cost is about the same as the Subtask 1.1 Wabash River

[3] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.

Greenfield Plant which cost 452.6 million mid-year 2000 dollars and produces 269.3 MW (1,680 $/KW). On a cost per unit of export power basis, this is substantial reduction of about 34%.

The Subtask 1.4 plant also costs less than the current day Subtask 1.5 IGCC Coal Power Plant which cost 1,318 $/KW (375 million mid-year 2000 dollars and produces 284.6 MW). On a cost per unit of export power basis, this is reduction of about 15%.

As the discounted cash flow analysis, will show, this coal IGCC plant can be competitive with new natural gas combined cycle plants at current economic conditions and natural gas costs.

Availability

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[4] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the Subtask 1.4 Optimized Coal to Power IGCC Plant design. Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.4 plant both as only a coal fueled facility and when backup natural gas is used to fire the combustion turbine when syngas was unavailable.[5]

Table 5 presents the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.4 Optimized Coal to Power IGCC Plant, both with and without the use of backup natural gas, the Subtask 1.1 Wabash River Greenfield Plant, and the current Subtask 1.5 Coal to Power Plant. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and for the coal feed rates. Defining average (or equivalent) availability as the daily average rate relative to the design rate, the Subtask 1.4 plant has the highest average syngas/power train availability of 79.8%, the Subtask 1.5 coal plant has a syngas/power train availability of 78.2%, and the Subtask 1.2 plant has the lowest average syngas/power train availability of 75.5%. With natural gas backup, the power availability of the Subtask 1.4 Optimized Coal to Power IGCC Plant increases to 92.0%.

Discounted Cash Flow Financial Analysis

A financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[6] This model calculates investment decision criteria used by industrial end-users and

[4] "Wabash River Coal Gasification Repowering Project, Final Technical Report," U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.
[5] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, August 1985.
[6] Nexant, Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation," Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

project developers to evaluate the economic feasibility of IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) projects summary result sheets. Appendix B contains the basic model input information used in the Subtask 1.4 financial analysis.

Table 6 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants. (The other basic economic parameters are shown in the middle column of Table 7.) With a 10% loan interest rate and without natural gas backup, the future Subtask 1.4 Optimized Coal to Power IGCC Plant has the lowest required selling price of 42.5 $/MW-hr (or 4.25 cents/kW-hr) to produce a 12% after-tax return on investment. The current Subtask 1.5 Coal to Power Plant requires a 53.9 $/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 67.5 $/MW-hr power selling price for a 12% after-tax return on investment.

With the use of 2.60 $/MMBtu backup natural gas to fire the combustion turbines when syngas is not available, the required power selling prices for a 12% after-tax return on investment are even lower. The Subtask 1.4 case now requires a power selling price of only 39.8 $/MW-hr, and the Subtask 1.5 coal case requires a power price of 48.9 $/MW-hr. Figure 1 shows the return on investment for the Subtask 1.4 and 1.5 plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 10% loan interest rate. This figure graphically shows how the return on investment has increased as a function of the power selling price as a result of the design improvements and operational experience that have been made since the Wabash River Repowering Project was built.

Also shown on Figure 1 is the calculated power selling price of 36.3 $/MW-hr for a natural gas combined cycle power plant (costing 450 $/KW of export power) with 3.00 $/MMBtu natural gas using the same financial assumptions as given in Appendix B, but with a shorter construction period. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 40.29 $/MW-hr to produce a 12% ROI, about 1.36 $/MW-hr greater than that of the natural gas combined cycle plant. At a natural gas price of 3.50 $/MMBtu (and a corresponding power price of 40.44 $/MW-hr), both the natural gas combined cycle plant and the coal-fired IGCC plants will have a 12.0% ROI.

These power selling prices are competitive with the 2001 EIA projections of an average electric selling price of just over 6 cents/kW-hr for the next two decades.[7]

Table 7 shows the sensitivity of some individual component prices and financial parameters for the future Subtask 1.4 Optimized Coal to Power IGCC Plant starting from a 12% ROI (with a power price of 42.77 $/MW-hr). Each item was varied individually without affecting any other item. Most sensitivities are based on a $\pm$10% change from the base value except when either a larger or smaller change is used because it either makes more sense or it is needed to show a meaningful result. The power selling price is the most significant product price with a 10% increase resulting in a 5.22% increase in the ROI to 17.22%, and a 10% decrease resulting in a 5.62% decrease in the ROI to 6.38%. Changes in the sulfur and slag prices have only a small influence on the ROI.

[7] Energy Information Administration, "Annual Energy Outlook With Projections to 2020," U. S. Department of Energy, Washington, DC, www.eia.doe.gov/oiaf/aeo, December, 2000.

A decrease in the coal price of 5 $/ton from the base coal price of 22.0 $/ton will increase the ROI by 1.80% to 13.8% and a 5 $/ton increase in the coal price will lower the ROI by 1.82% to 10.18%.

A 5% decrease in the plant cost to 441.4 MM$ will increase the ROI by 1.83% to 13.83%, and a 5% increase in the plant cost to 487.9 MM$ will decrease the ROI by 1.68% to 10.32%.

The loan interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.78% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.20%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.59% to 11.41%, and a 20% increase in the loan amount to 88% will increase the ROI by 1.01% to 13.01%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.48%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.52% to 11.48%.

If the plant performance can be increased by 2.5% by improving the thermal efficiency of the plant so that the design power output increases to 426.9 MW from 416.5 MW, then the ROI increases by 1.34% to 13.34%. Conversely, a 2.5% decrease in plant performance which reduces the power output to 406.1 MW will lower the ROI by 1.35% to 10.65%.

Effect of Loan Interest Rate

The second line of Table 6 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants with a 8% loan interest rate. As is the case with the 10% loan interest rate cases, there is an additional 3% financing fee on the amount of the loan. With a 8% loan interest rate and without natural gas backup, the future Subtask 1.4 Optimized Coal to Power IGCC Plant still has the lowest required selling price of 39.9 $/MW-hr (or 3.99 cents/kW-hr) to produce a 12% after-tax return on investment. The current 1.5 Coal to Power Plant requires a 50.4$/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 62.9 $/MW-hr power selling price for a 12% after-tax return on investment.

With 2.60 $/MMBtu HHV backup natural gas, the required power selling prices are further reduced. The Subtask 1.4 case now requires a power selling price of only 37.3 $/MW-hr, and the Subtask 1.5 coal case requires a power price of 45.9 $/MW-hr. Figure 2 shows the return on investment for the Subtask 1.4 and 1.5 plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 8% loan interest rate. This figure is similar to Figure 1, but a comparison with it shows how influential the loan interest rate is on the return on investment.

Also shown on Figure 2 is the calculated power selling price of 35.4 $/MW-hr for a natural gas combined cycle power plant with a GE 7FA+e combustion turbine (costing 450 $/KW of export power) with 3.00 $/MMBtu HHV natural gas using the same financial assumptions as given in Appendix B, but with a shorter construction period and an 8% loan interest rate. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 37.69 $/MW-hr to produce a 12% ROI, slightly below that of the natural gas combined cycle plant. At a natural gas price of 3.28 $/MMBtu (and a corresponding power price of 37.69 $/MW-hr), both the natural gas combined cycle plant and the coal-fired IGCC plants will have a 12.0% ROI.

Effect of Syngas Availability

After commissioning all plants undergo a “learning curve” during which problem areas are corrected, inadequate equipment is replaced, and adjustments are made. Consequently, performance improves as measured by increased capacity or improved on-stream factors. Figure 3 shows the effect of improved syngas availability on the required power selling price for a 12% ROI. As the syngas availability improves, the amount of supplemental natural gas is reduced causing the difference between the cases with and without natural gas to decrease. At the unattainable 100% syngas availability, there is no difference between the two cases.

For the case without natural gas backup, Increasing the syngas availability from 79.8 to 85% reduces the required power selling price for a 12% ROI by about 2.25 $/Mw-hr from 42.77 to 40.53 $/MW-hr. With natural gas backup, the reduction is not as great, about 1.73 $/MW-hr from 39.76 to 38.59 $/MW-hr.

Figure 4 shows the effect of syngas availability on the return on investment without natural gas backup at a power selling price of 42.77 $/MW-hr. In this case, increasing the syngas availability from 79.8 to 85% increases the return on investment by about 3% from 12.0 to 15.0%. This figure points out the strong incentive for designing and building a plant that will have high syngas availability.

Figure 5 shows the effect of Syngas Availability on the Net Present Value @ 12% without natural gas backup at a power selling price of 42.77 $/MW-hr with the same economic scenario as is used in Figure 4. Increasing the syngas availability from 79.8 to 85% increases the NPV by 15.7 MM$; again justifying the incentive for designing and building a plant that will have a high syngas availability.

Additional Design Enhancements and Efficiency Improvements

After the design of the future Subtask 1.4 Optimized Coal to IGCC Power Plant was completed, two additional design enhancements were identified that further reduce the plant cost and increase the thermal efficiency. They are:

1. Improved design for the E-150 syngas cooler heat exchanger. The improved design for this heat exchanger costs 2.55 MM$ less than the cost estimate that was used in developing the cost basis for the Subtask 1.4 plant.

2. Improved design for the sour water stripper. The use of more corrosion resistant and more expensive metallurgy in the sour water stripper that allows the build up of chlorides in the wash water and reduces the size of the stripper and associated equipment. This also significantly reduces the amount of steam consumed and increases the power output. The net result of this modification is that the plant cost increases by 3.43 MM$ and the output power increases by 8.4MW.

Table 8 summarizes the effect of these design enhancements. The net result of these two changes is that the power output has increased by 8.4 MW to 424.9 MW and the plant cost has increased by 0.88 MM$ to 465.54 MM$. The revised plant efficiency is 45.4% HHV (47.1% LHV). The plant cost now is 1,096 $/KW of export power.

Table 9 shows the effect on these design enhancements on the required power selling price to produce a 12% return on investment. These enhancements reduce the required power selling prices between 0.7 and 0.8 $/MW-hour or about 2%. Thus, making coal IGCC power plants more competitive with natural gas combined cycle plants.

Besides the above design enhancements, other potential improvements that may reduce the cost and/or increase the plant efficiency include:

- ◊ Further improvements in combustion turbine technology and/or efficiency
- ◊ Dry low NOx burners
- ◊ Simplified heat recovery
- ◊ Warm gas cleanup
- ◊ Multiple gasification trains

Additional efficiency enhancements at low to moderate cost increases include:

- ◊ Increased steam cycle pressure
- ◊ Inlet air chillers
- ◊ Steam bottoming cycle (Kalina cycle)
- ◊ Moderate sulfur coal

These enhancements should allow the next generation IGCC plant to approach a 50% efficiency and a capital cost of 1000 $/kW.

Summary

The objective of Subtask 1.4 was to design a future, single-train, coal fueled IGCC power plant using an advanced "G/H-class" gas turbine that is expected to be available near the end of this decade. The design presented in this report satisfies that objective. It processes 3,007 TPD of dry Illinois No. 6 coal and produces 416.5 MW of export power at an installed cost of 464.6 million mid-year 2000 dollars or 1,115 $/kW of export power. Since the plant design was frozen, two design enhancements were developed that increase the export power to 424.9 MW and reduce the plant cost to 1096 $/kW. Overall, the emissions performance of this plant is significantly better than the emissions performance of the Subtask 1.1 Wabash River Greenfield Plant and the current day Subtask 1.5 IGCC Coal Power Plant.

The economics also are more favorable because of

- The Value Improving Practices that were employed in developing the design
- The use of a larger, more efficient "G/H-class" combustion turbine
- Integrating the combustion turbine and the Air Separation Unit
- Economies of scale

For a 12% return on investment without supplemental natural gas and a 10% project financing rate, the required export power selling price dropped from 67.5 $/MW-hr for the Subtask 1.1 Wabash River Greenfield Plant to 53.9 $/MW-hr for the current Subtask 1.5 IGCC Coal Power Plant, and to 42.8 $/MW-hr for the Subtask 1.4 Optimized Coal to Power IGCC Plant. Compared to the Subtask 1.1 Wabash River Greenfield Plant, this is a savings of over 36%. The use of supplemental natural gas will further reduce the required selling price to 39.8 $MW-hr for the Subtask 1.4 plant.

In today's current economic situation, an 8% interest loan with a 3% upfront financing fee may be possible. Under these conditions, the required export power selling price for the coal fired IGCC plant to produce a 12% ROI drops to 37.69 $/MW-hr with the use of supplemental 2.60 $/MMBtu HHV natural gas. Without supplemental natural gas the required power selling price is 39.88 $/MW-hr. At these power prices, this coal-fired IGCC power plant is competitive with new natural gas combined cycle power plants using 3.00 $/MMBtu HHV natural gas.

Table 1

Design Feed and Product Rates for the Subtask 1.4, 1.1 and 1.5 Single-train Coal IGCC Power Plants

	Subtask 1.4 Optimized Coal to Power IGCC Plant	Subtask 1.1 Wabash River Greenfield Plant	Subtask 1.5 Current Design IGCC Power Plant
Feeds			
Coal, TPD dry	3,007	2,259	2,335
Natural Gas, MMscfd	0	0	0
River Water, gpm	3,079	2,281	2,836
Products			
Power, MW	416.5	269.3	284.6
Sulfur, TPD	76.7	57	60
Slag, TPD	462	356	364
Performance			
Oxygen Consumption,			
TPD of 95% O_2	2,294	2,130	1,900
Tons of O2/ton of dry coal	0.72	0.89	0.81
Water Discharge, gpm			
Process Water	0	120	72
Clear Water*	703	643	826
Total Discharge	703	763	898
Heat Rate, Btu/kW	7,671	8,912	8,717
Thermal Efficiency, % HHV	44.5	38.3	39.1
Emissions			
SO_2, lb/MW-hr	0.09	1.16	0.50
CO, lb/MW-hr	0.11	0.21	0.14
NOx, lb/MW-hr	0.30	0.60	0.25
Sulfur Removal, %	99.7	96.7	98.5
Plant Area, acres	40	61	40
Installed Cost, million mid-2000 $	464.6	452.6	375
Installed Cost, $/KW	1,115	1,680	1,318

* Clear water discharge includes a 150 gpm allowance for storm water.

Table 2

IGCC Performance Summary
Comparison with a Previous Study+

	Alternate Designs+			
Case Designation	**9H_HEQ_C @ 50 Hz**	**9H_RO_C @ 50 Hz**	**Task 1.4 "G/H-class" @ 60 Hz**	**Ratio to 9H_RO_C @ 60 Hz**
Gas Turbine / ASU Integration	Full	Full	Full	
Fuel Feed (STPD dry)	3942	3940	3007	0.763
Fuel HHV (MMBtu/hr)	4125	4124	3195	0.775
Pure O_2 Feed (STPD)	3578	3576	2164	0.605
Gas Turbine LHV (MMBtu/hr)	2922.5	2922.6	2427	0.830
Combined Cycle Gross MW	550.9	574.2	452.7*	0.788
IGCC Gross MW	569.7	574.2	452.7*	0.788
Total Auxiliary MW	49.0	46.6	36.2	0.777
IGCC Net MW	520.9	527.6	416.5	0.789
Net IGCC Efficiency (HHV)	43.1	43.7	44.5	1.018
Net IGCC Efficiency (LHV)	44.6	45.2	46.2	1.022
Sulfur (STPD)	39.2	39.2	77	1.964
Solid Waste (STPD)	394.2	394.2	466	1.182
NO_X (ppmv/dry @ 15% O_2)	<25	<25	10	0.40
SO_X (lb/MMBtu)	0.02	0.02	0.01	0.50
HRSG Exit Flow (lb/sec)	1654.4	1654.9	1338	0.808
HRSG Exit Temp. (^oF)	265	243	237	
Air Extraction (lb/sec)	369	369	226	0.612
N2 Injection (lb/sec)	291.3	291.3	181.9	0.624
Air Flow (lb/sec) For Natural Gas Case	-- 1510	-- 1510	1202 1230	-- 0.815

+ Falsetti, J. S. et al, "From Coal or Oil to 550 MWe via 9H IGCC," Gasification Technologies Conference, San Francisco, Oct. 9-11, 2000.
* Gross combined cycle power production minus consumption in combined cycle auxiliaries

HEQ_C => High Efficiency Quench on Coal feed
RO_C => Radiant Only Heat Recovery on Coal feed (similar to Global Energy's design)

Table 3

Environmental Emissions Summary of the Subtask 1.1, 1.4 and 1.5 Single-Train Coal Power Plants*

Case	Subtask 1.4	Subtask 1.1	Subtask 1.5
Description	Optimized IGCC Design	Wabash River Greenfield Plant	Current Design IGCC Power Plant
Feedstock	Illinois No. 6 Coal	Illinois No. 6 Coal	Illinois No. 6 Coal
Total Gas Turbine Emissions			
GT/HRSG Stack Flow Rate, lb/hr	4,817,100	3,770,200	3,983,500
GT/HRSG Stack Exhaust Temperature, ^{o}F	246	238	222
Emissions (at 15% oxygen, dry)			
SOx, ppmvd	2.4	3	3
SOx, as SO_2, lb/hr	25	23	24
NOx, ppmvd	10	25	10
NOx as NO_2, lb/hr	127	160	69
CO, ppmvd	10	15	10
CO, lb/hr	47	55	40
Incinerator Emissions			
Stack Flow Rate, lb/hr	10,800	22,120	21,870
Stack Exhaust Temperature, ^{o}F	653	500	500
Emissions (at 3% oxygen, dry)			
SOx, ppmvd	489	6,662	2,473
SOx, as SO_2, lb/hr	11.5	290	118
NOx, ppmvd	40	40	40
NOx as NO_2, lb/hr	0.3	1	1
CO, ppmvd	50	50	50
CO, lb/hr	0.5	1	1
Total Plant Emissions			
Exhaust Flow Rate, lb/hr	4,827,900	3,792,300	4,005,300
Emissions			
SOx, ppmvd	4	42	19
SOx, as SO_2, lb/hr	37	312	142
NOx, ppmvd	18	30	13
NOx as NO_2, lb/hr	127	161	69
CO, ppmvd	11	17	13
CO, lb/hr	47	56	41
VOC and Particulates, lb/hr	NIL	NIL	NIL
Opacity	0	0	0
Sulfur Removal, %	99.7	96.8	98.6

* Expected emissions performance

Table 4

Subtask 1.4 VIP and Optimization Items

Plant Section	Description
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Redesigned the gasifier for high pressure and increased capacity • Used slurry feed vaporization in the gasifier second stage • Maximized syngas moisturization • Used a cyclone and an advanced dry char filter system to remove particulates from the syngas • Improved the burner design
400/420	Simplified Claus plant, amine, and sour water stripper resulting in lower incinerator emissions
500	• Used a state-of-the-art advanced “G/H-class” gas turbine with 300 MW output and lower NOx • Used full air/N2 Air Separation Unit integration to balance flows in the gas turbine • Used nitrogen diluent and moisturizationin the gas turbine
900	• Zero process water discharge • Use of a single cooling tower for the entire plant
General	• Bechtel’s Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach • Bechtel’s MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • Availability analysis was used to select design with maximum on-stream time • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 5

Design and Daily Average Feed and Product Rates for the Subtask 1.4, 1.1 and 1.5 Single-train Coal IGCC Power Plants

	Subtask 1.4 Optimized Coal to Power IGCC Plant			Subtask 1.1 Wabash River Greenfield		Subtask 1.5 Current Design IGCC Power Plant		
		Daily Average			Daily Average		Daily Average	
	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	Design	Without Backup Gas	With Backup Gas
Feeds								
Coal, TPD dry	3,007	2,400	2,400	2,259	1,705	2,335	1,826	1,826
Natural Gas, Mscfd	0	0	8,896	0	0	0	0	6,929
River Water, gpm	3,079	2,457	NC	2,281	1,722	2,836	2217	NC
Products								
Export Power, MW	416.5	332.4	387.8	269.3	203.2	284.6	222.5	264.4
Sulfur, TPD	76.7	61.2	61.2	57	43	60	46.9	46.9
Slag, TPD	462	368.7	368.7	356	281	364	284.6	284.6
Performance								
Oxygen Consumption,								
TPD of 95% O_2	2,294	1,831	1,831	2,130	1,608	2,015	1,576	1,576
TPD O_2/TPD dry coal	0.76	0.76	0.76	0.94	0.94	0.86	0.86	0.86
Water Discharge, gpm								
Process Water	0	0	0	120	91	72	56	56
Clear Water	703	561	NC	643	485	640	500	NC
Total Discharge	703	561	NC	763	576	712	557	NC
Heat Rate, Btu/kW	7,671	7,671	7,531	8,912	8,912	8717	8,717	8,429
Thermal Efficiency, %	44.5%	44.5%	45.3%	38.3%	38.3%	39.1%	39.1%	40.5%
Emissions								
SO_2, lb/MW-hr	0.09	0.09	0.08	1.16	1.16	0.50	0.50	0.42
CO, lb/M-hr	0.11	0.11	NC	0.21	0.21	0.14	0.14	NC
NOx, lb/MW-hr	0.30	0.30	NC	0.60	0.60	0.24	0.24	NC
Sulfur Removal, %	99.7	99.7	99.7	96.8	96.8	98.5	98.5	98.5
Plant Area, acres	40			61		40		
Installed Cost, MM$[2]	464.6			452.6		375		
Installed Cost, $/kW	1,115			1,680		1,318		

NC = Not Calculated

Table 6

Required Power Selling Prices for a 12% Return on Investment

	Power Selling Price, in $/MW-hr				
	Subtask 1.4		Subtask 1.5		Subtask 1.1
Loan Interest Rate	Without Natural Gas	With Natural Gas	Without Natural Gas	With Natural Gas	Without Natural Gas
10%	42.77	39.77	53.89	48.86	67.49
8%	39.88	37.28	50.39	45.92	62.87

Table 7

Sensitivity of Individual Component Prices and Financial Parameters on the Subtask 1.4 Base Case Starting from a 12% ROI

(with a Power Price of 42.774 $/MW-hr and without Backup Natural Gas)

	Decrease			Base	Increase		
	ROI	Value	% Change	Base Value	% Change	Value	ROI
Products							
Power	6.38%	38.497 $/MW-hr	-10%	**42.774 $/MW-hr**	+10%	47.051 $/MW-hr	17.22%
Sulfur	11.98%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.02%
Slag	11.75%	-5 $/t	---	**0 $/t**	---	5 $/t	12.25%
Feed							
Coal	13.80%	17 $/t	-23%	**22.0 $/t**	23%	27 $/t	10.18%
Financial							
Plant Cost	12.89%	453.0 MM$	-2.5%	**464.656 MM$**	+2.5%	476.3 MM$	11.15%
Plant Cost	13.83%	441.4 MM$	-5.0%	**464.656 MM$**	+5.0%	487.9 MM$	10.32%
Interest Rate	15.78%	8%	-20%	**10%**	+20%	12%	8.18%
Loan Amount	11.41%	72%	-20%	**80%**	+20%	88%	13.01%
Tax Rate	12.48%	36%	10%	**40%**	+10%	44%	11.48%
Performance							
Design Power	10.65%	406.1 MW	-2.5%	**416.5 MW**	+2.5%	426.9 MW	13.34%
Design Power	9.26%	395.7 MW	-5.0%	**416.5 MW**	-5.0%	437.3 MW	14.66%

Table 8

Effect of Design Enhancements

	Export Power, MW	Total Installed Cost MM$	Total Installed Cost $/KW
Subtask 1.4 Basic Design	416.5	464.656	1116
Design Enhancements			
Improved E-150	0	-2.55	-7
Redesigned SWS System	+8.4	+3.43	-20
Enhanced Design	424.9	465.536	1096

Table 9

Effect of the Design Enhancements on the Required Power Selling Price for a 12% Return on Investment

	Loan Interest Rate, %	Subtask 1.4 Basic Design	Enhanced Design	Difference
Without Backup Natural Gas				
Required Power Selling Price for a 12%, ROI, $/MW-hr	10	42.77	41.98	-0.79
	8	39.88	39.13	-0.75
With Backup Natural Gas				
Required Power Selling Price for a 12%, ROI, $/MW-hr	10	39.77	39.01	-0.76
	8	37.28	36.57	-0.71

Figure 1

Effect of Power Selling Price on the Return on Investment at a 10% Loan Interest Rate

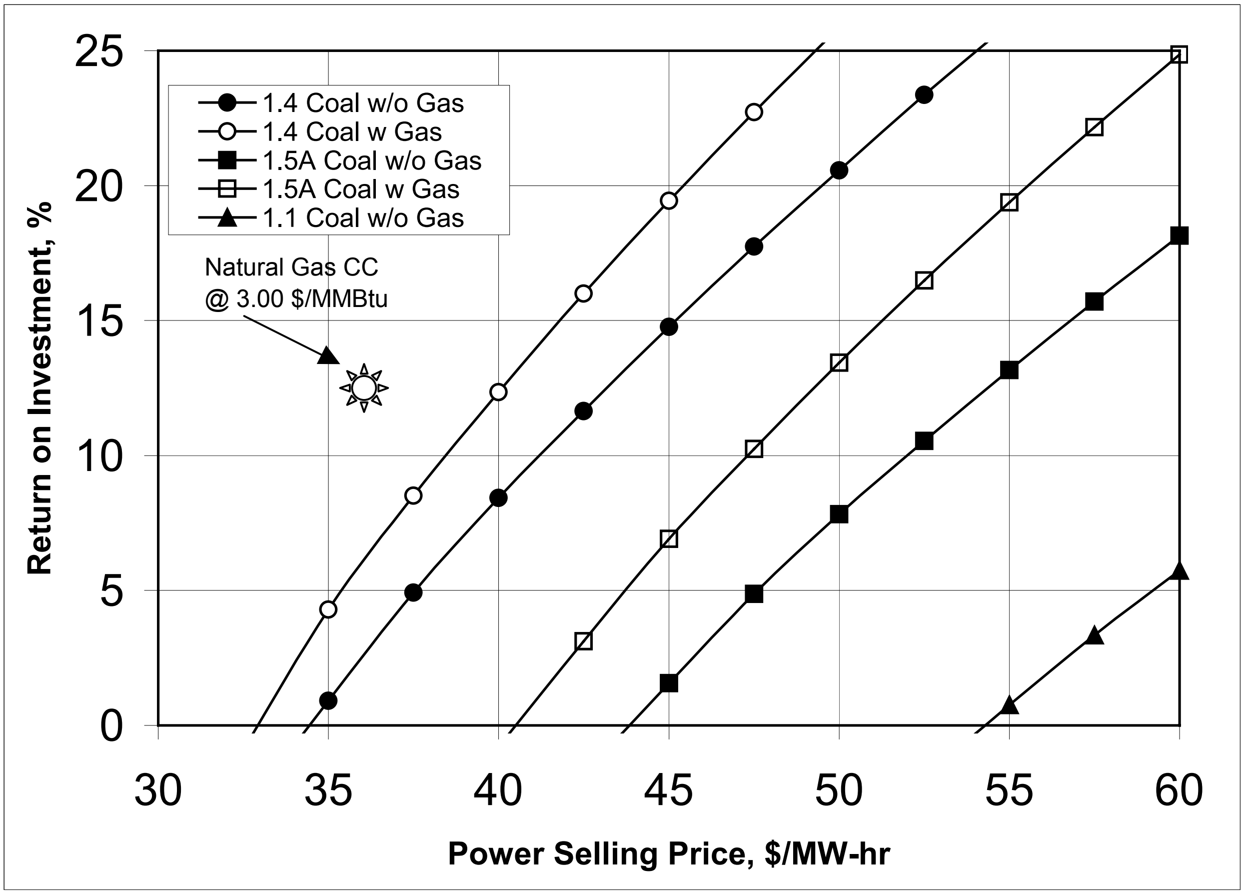


Figure 2

Effect of Power Selling Price on the Return on Investment at a 8% Loan Interest Rate

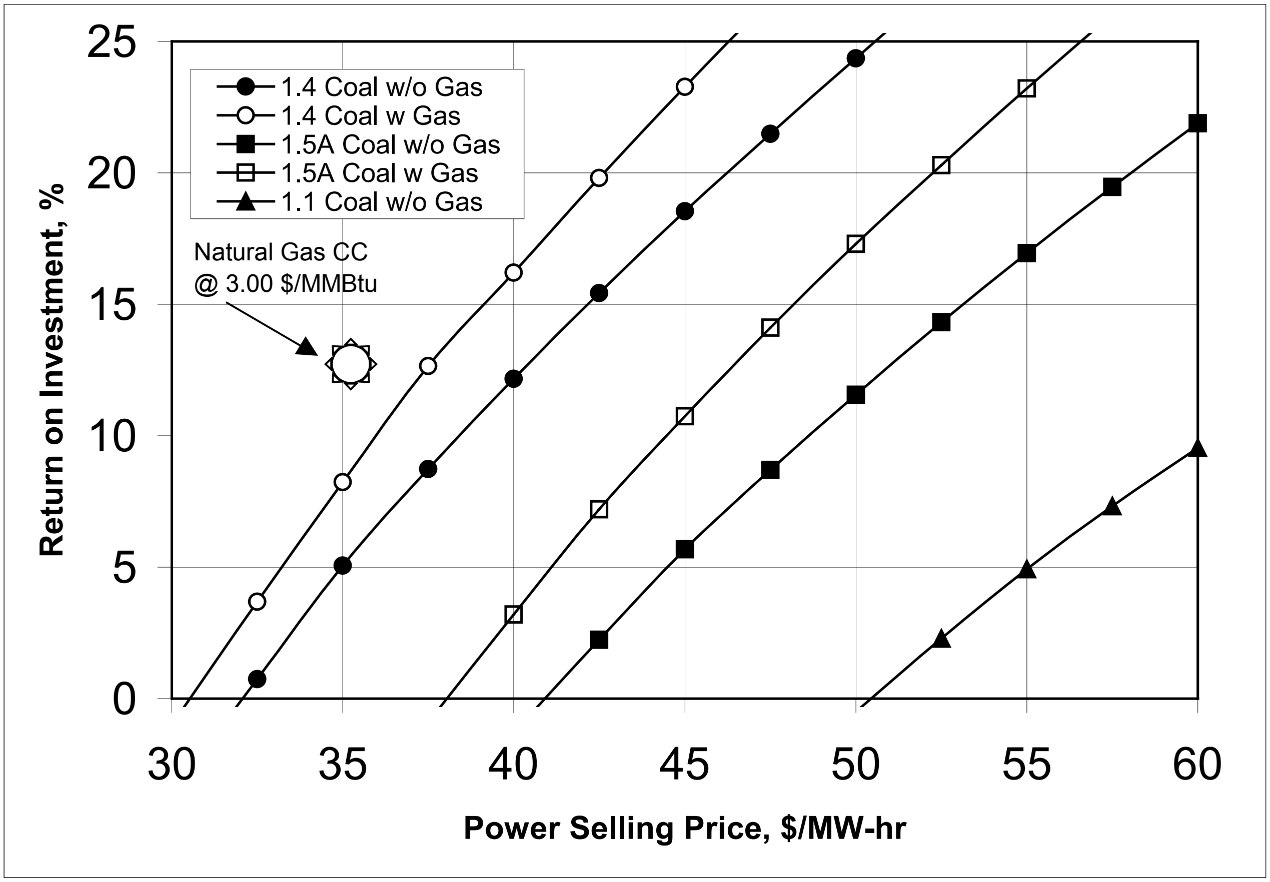


Figure 3

Effect of Syngas Availability on the Required Power Selling Price for a 12% Return on Investment

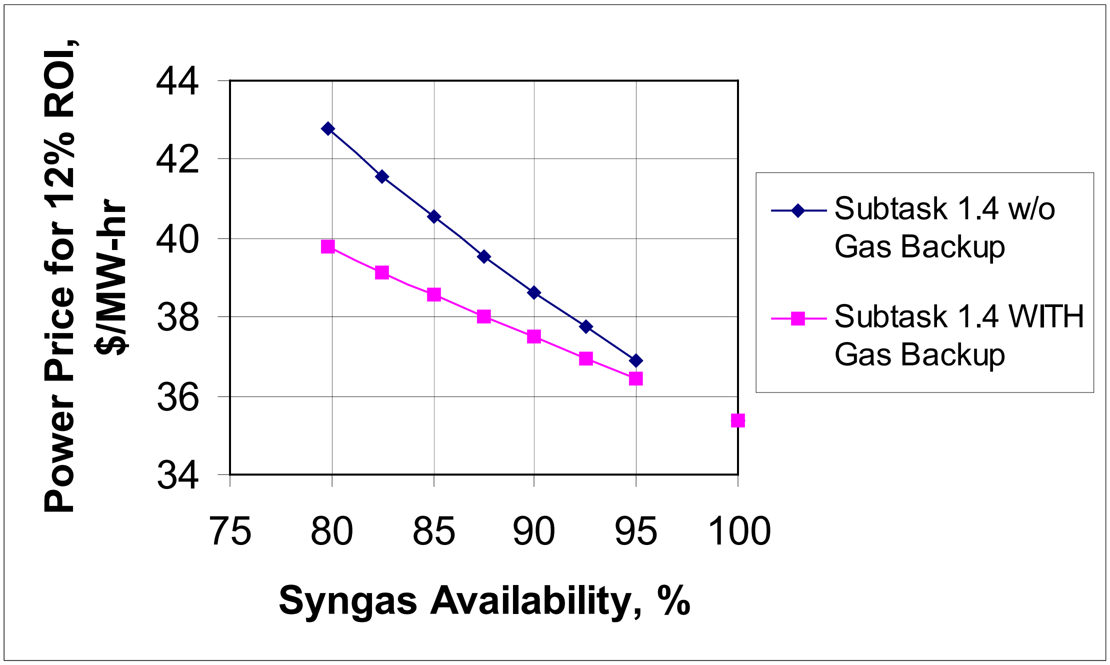


Figure 4

Effect of Syngas Availability on the Return on Investment Without Gas Backup at a Power Selling Price of 42.77 $/MW-hr

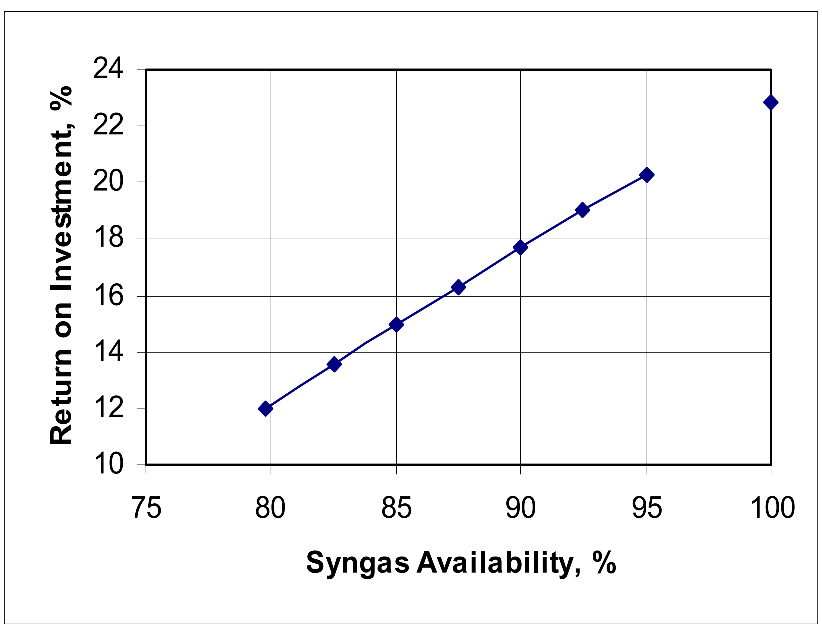
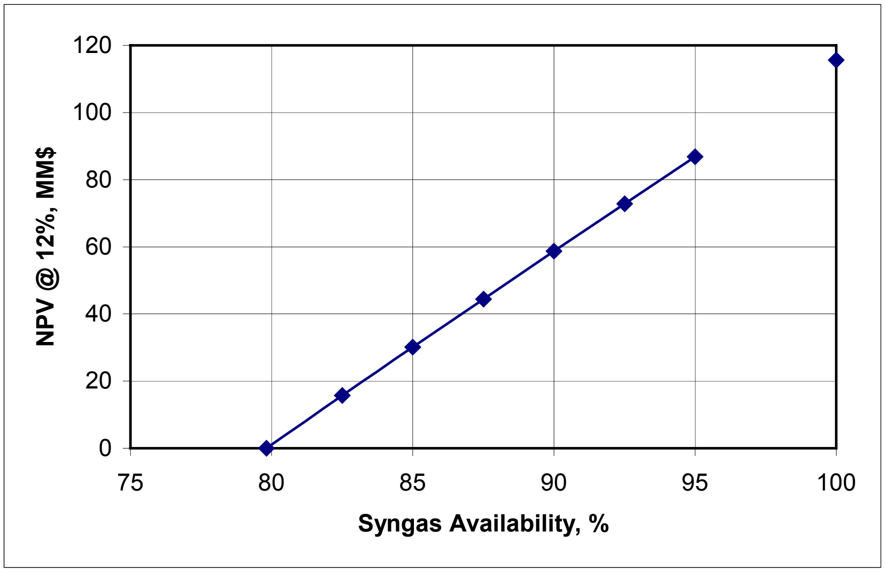


Figure 5

Effect of Syngas Availability on the Net Present Value @ 12% Return on Investment Without Gas Backup at a Power Selling Price of 42.77 $/MW-h



Appendix E

Subtask 1.4 (Appendix A)

Optimized Coal to Power IGCC Plant

Subtask 1.4 (Appendix A)
Table of Contents

Figures

Appendix A

Subtask 1.4 – The Optimized Coal to Power IGCC Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7FA gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest originally processing Illinois No. 6 coal. Subtask 1.2 developed a design and current cost for a Coal to Power IGCC plant producing electric power, hydrogen, steam, and fuel gas at a Gulf Coast location adjacent to a refinery

Subtask 1.3 optimized the Subtask 1.2 facility to develop an Optimized Petroleum Coke IGCC Coproduction Plant producing electric power, hydrogen and steam at a Gulf Coast location adjacent to a petroleum refinery. The plant design was optimized using both Global Energy's petroleum coke gasification experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures.

This appendix summarizes the results of Subtask 1.4. The objective of Subtask 1.4 is to develop a design and installed capital cost for a future, highly optimized advanced design coal to power IGCC plant using an advanced gas turbine that is expected to be commercially available near the end of the decade. This plant incorporates the Value Improving Practices (VIP) results that were developed as part of Subtask 1.3 and several additional items specifically for Subtask 1.4, to create an optimized facility for the production of power from coal.

Bechtel and Global Energy implemented a project specific Value Improving Practices program to reduce the installed and operating costs associated with the plant to develop the design for the Optimized Coal to Power IGCC Plant. The VIP team included process design and construction specialists from Bechtel, gasification experts from Global Energy, and operating and maintenance personnel from the Wabash River Repowering Project. The team implemented Value Improving Practices covering the following areas to improve the plant performance and return on investment.

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Design-to-Capacity

- Traditional Value Engineering
- Process Availability (Reliability) Modeling
- Plant Layout Optimization
- Constructability Review / Schedule Optimization
- Operation and Maintenance and Savings

This appendix contains the following design and cost information:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the coal to power IGCC plant
- Artist's view of the plant
- Overall material, energy and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

The following sections describe the results of Subtask 1.4, the design and cost estimate for the future Optimized Coal to Power IGCC Plant.

Section A2 contains the design basis for the Subtask 1.4 Optimized Coal to Power IGCC Plant. Section A3 contains descriptions of the various sections of the plant. Section A4 summarizes the overall plant performance. Section A5 contains a listing of the major pieces of equipment within the plant. Section A6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the future Optimized Coal to Power IGCC Plant. Many design parameters are essentially the same as that of the non-optimized Wabash River Greenfield coal to power IGCC plant of Subtask 1.1, as previously described.

A.2.1 Capacity

The Optimized Coal to Power IGCC Plant will process a nominal 3,000 TPD of Illinois No. 6 coal (dry basis) to produce syngas that will fully load one advanced “G/H-class” gas turbine at 59°F ambient, 60% relative humidity, and 14.43 psia to produce power. Sulfur and slag are the only coproducts.

A.2.2 Site Conditions

Location	Typical Mid-Western State
Elevation, ft	500
Air Temperature	
Maximum, °F	93
Annual, °F	59
Minimum, °F	-20
Summer Wet Bulb, °F	70
Relative Humidity, %	60
Barometric Pressure, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

A.2.3 Coal

Type	Illinois No. 6	
	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,495
Analysis, wt%		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

A.2.4 Water

Cations	mg/L	As equivalent ppm of CaCO3
Aluminum	0.006	0.033
Arsenic	0.002	
Barium	0.055	0.040
Boron	0.154	
Calcium	74.0	185
Chromium	0.005	
Copper	0.002	0.003
Iron	0.028	0.050
Lead	<0.001	0.000
Lithium	0.006	
Magnesium	26.0	107.1
Manganese	0.009	0.016
Molybdenum	0.008	
Potassium	4.8	6.1
Sodium	33.0	71.9
Selenium	<0.001	
Strontium	0.297	0.339
Vanadium	0.010	
Zinc	0.008	0.012
Total Cations		371

Anions	mg/L	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	245.0	200.9
Chloride	44.0	62.0
Sulfide	79.0	82.2
Nitrate - Nitrogen	4.88	4.0
Phosphorus	0.538	4.482
Fluoride	0.25	0.665
Chloride (add to balance)	12.0	16.9
Total Anions		371

Weak Ions	mg/L	As equivalent ppm of CaCO3
Ammonia Nitrogen	0.132	
Dissolved Silica	7.1	

Other Characteristics	mg/L	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	419	
Standard Conductivity	671	
Total Alkalinity		201
Total Hardness		290
Total Organic Carbon	4 to 11.2	
Turbidity	8 to 100	
PH	7.6 to 8.4	
Total Nitrogen	6.1	
Total Suspended Solids	23 to 336	

A.2.5 Natural Gas

Natural gas will be available for startup and for supplemental firing of the combustion turbines and HRSG. The natural gas will have a HHV of 1,000 Btu/scf and a LHV of 900 Btu/scf.

A.3 Plant Description

A.3.1 Block Flow Diagram

The Optimized Coal to Power IGCC Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier/High Temperature Heat Recovery (HTHR)/Cyclone and Dry Char Filter Particulate Removal System
    - Sulfur Removal
    - Sulfur Recovery
- Air Separation Unit (ASU)
- Power Block
    - Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG)
    - Steam Turbine Generator(STG)/Auxiliary Equipment
- Balance of Plant

Figure A1 is the block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the relative capacity of each train are noted on the BFD.

A.3.2 General Description

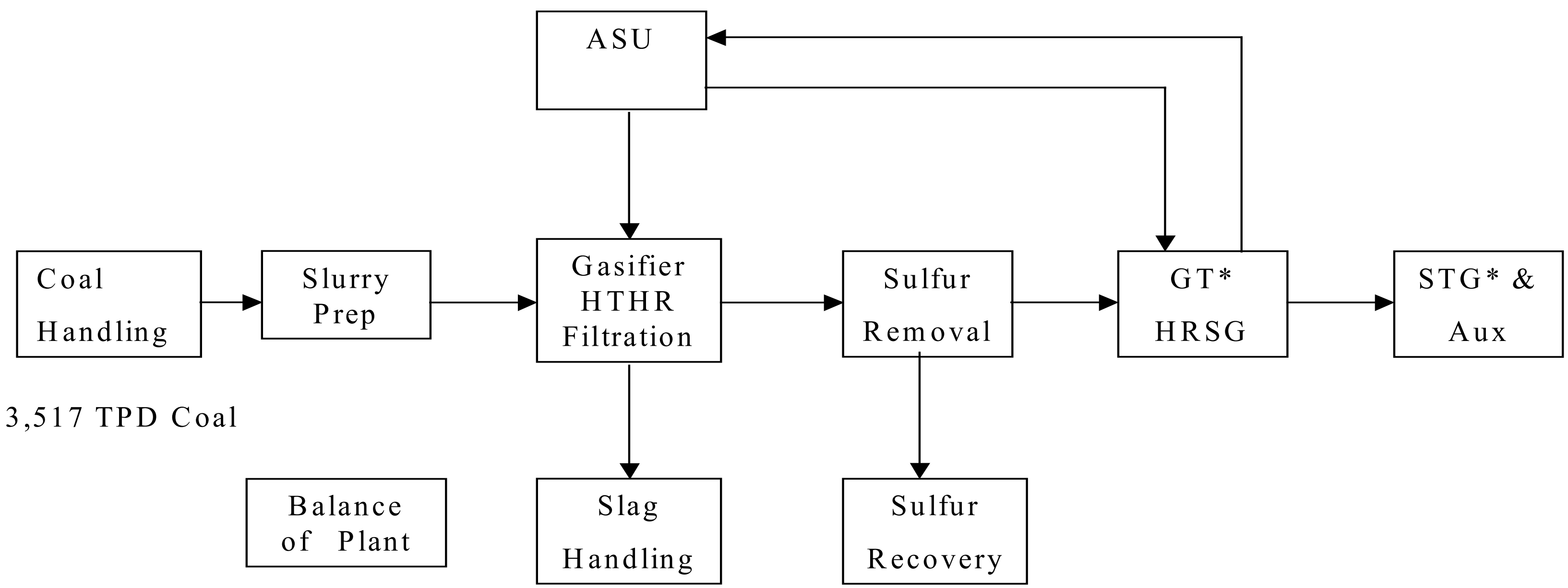
The plant is divided into the five distinct areas.

- Fuel Handling Unit
- Gasification Plant
- Air Separation Unit
- Power Block
- Balance of Plant

Section A.3.3 describes the additional fuel handling facilities required for the coal from unloading to on-site storage and conveying to the gasification plant.

Section A.3.4 describes the Global Energy gasification plant. This plant employs an advanced oxygen-blown, two-stage entrained flow gasifier to convert the coal to syngas. The gasification plant includes several process units to remove impurities from the syngas. However, the dry char filtration system used at the Wabash River Repowering Project to remove particulates from the syngas has been replaced by a lower cost cyclone and dry char filter system.

Figure A1
FUTURE OPTIMIZED COAL TO POWER IGCC PLANT



Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95% purity oxygen stream is produced as the oxidant for the gasifier. The ASU is fully integrated with the combustion gas turbine eliminating the need for a separate air compressor.

Section A.3.6 describes the power block, which consists of an advanced “G/H-class” gas turbine with generator. The gas turbine generator uses a combination of moisturized syngas and nitrogen injection for NOx control.

Section A.3.7 describes the balance of plant (BOP). The BOP portion of the Optimized Coal to Power IGCC Plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist’s conception of the Optimized Coal to Power IGCC Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were generated by the Comet model.

A.3.3 AREA 100 – Fuel Handling

The coal handling system provides the means to receive, unload, store, reclaim, and convey coal to the storage facility. Coal is delivered to the site by rail and transferred to the gasification area through the coal unloading system to the crusher house. Coal also can be delivered by truck and dumped directly onto the coal pile when train deliveries are not available.

Coal is transferred from the crusher house to the active coal storage pile by transfer belt conveyors. Coal is reclaimed from the active coal storage pile to the gasification plant coal silo by variable rate feeder-breakers and the reclaim belt conveyors.

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur recovery. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

Coal slurry feed for the gasification plant is produced by wet grinding in a rod mill. A conveyor delivers the coal into the rod mill feed hopper. Water is added in order to produce the desired slurry solids concentration. The slurry water includes water that is recycled from other areas of the gasification plant. Prepared slurry is stored in an agitated tank.

All tanks, drums and other areas of potential atmosphere exposure of the product slurry or recycled water are closed and vented into the tank vent collection system for control of vapor emissions.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-Gas Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a refractory lined vessel into which oxygen and recycle char and unreacted coal are fired via a mixer nozzle. The coal char and oxygen are fed sub-stoichiometrically at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coal is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the coal is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are removed by downstream processing.

Mineral matter in the coal forms a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows upward from the first stage into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which a portion of the coal slurry feed stream is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This coal feed first lowers the temperature of the gas exiting the first stage by the endothermic nature of the reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by evaporation of the water entering with the coal slurry. No oxygen is introduced into the second stage.

The gas and entrained particulate matter (char and unreacted coal) exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

To remove solids from the syngas, the raw gas passes through a two-step particulate removal system consisting of a cyclone located upstream of the high temperature heat recovery unit and a dry char filter system located downstream. The recovered char and unreacted coal particles are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir at the top of the bin and goes to a settler where the remaining solids are collected. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, water circulation pumps, and a flash gas scrubber to remove residual H_2S. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

Filter syngas is scrubbed to remove water-soluble contaminants such as chlorides. The scrubbed syngas is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the downstream Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the desired high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The remaining stripped effluent water is processed in a zero process water discharge (ZLD) water treatment evaporation system. The recovered salts are sent to a suitable disposal site. Thus, no process wastewater is discharged from the Sour Water Treatment System. The water recovered from the evaporation process is recovered and recycled back in to the process.A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam-stripping at a lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiency.

A.3.4.5 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

The ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers. High pressure nitrogen is sent to the combustion turbine for use as a diluent.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous nitrogen production.

A.3.6 Power Block

The major components of the power block include a gas turbine generator (GTG), a heat recovery steam generator (HRSG), a steam turbine generator (STG), and numerous supporting facilities.

A.3.6.1 AREA 500 - Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and stack

The combustion turbine generator is an advanced “G/H-class” machine, nominal 300 MW output, that is expected to be available for syngas firing near the end of the decade. The gas turbine utilizes moisturized syngas with nitrogen injection for NO_x control. Combustion exhaust gases are routed from the GTG to the HRSG and stack. Natural gas is used as back-up fuel for the gas turbine during startup, shutdown, and short duration transients in syngas supply.

The HRSG receives the gas turbine exhaust gases and generates steam at the main steam and reheat steam energy levels. It generates high pressure (HP) steam and provides condensate heating for both the combined cycle and the gasification facilities.

The HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSG boiler includes a steam drum for proper steam purity and to reduce surge during cold start. Large unheated down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

Each stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 - Steam Turbine (ST)

The reheat, condensing turbine includes an integrated HP/IP opposed flow section and an axial flow LP section. Turbine exhaust steam is condensed in a surface condenser. The reheat design ensures high thermal efficiency and excellent reliability. It will produce about 164 MW of electric power.

A.3.6.3 Power Delivery System

The power delivery system includes the gas turbine generator output at 18 kilovolts (kV) with each connected through a generator breaker to its associated main power step-up transformer. A separate main step-up transformer and generator breaker is included for the steam turbine generator. The HV switch yard receives the energy from the three generator step-up transformers at 230 kV.

An auxiliary transformer is connected between the gas turbine generator breakers and the step-up transformers. Due to the large auxiliary load associate with the IGCC plant, internal power is distributed at 33 kV from the auxiliary power transformer. The major motor loads in the ASU plants will be serviced by 33/13.8 kV transformers. Several substations, with 33/4.16 kV transformers supplying double ended electrical bus, will serve the balance of the project loads.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.6.4 Cooling Water System

The single cooling water system provides the cooling duty for the power block, for the air separation unit, and for the gasification facility. The major components of the cooling water system consist of a single cooling tower and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. The cooling tower is a multi-cell mechanically induced draft tower, sized to provide the design heat rejection at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.7 AREA 900 - Balance of Plant

A.3.7.1 Fresh Water Supply

Industrial river water is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.7.2 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.7.3 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond and treated before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the waste water outfall system.

A.3.7.4 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The system consists of air compressors, air receivers, hose stations, and piping distribution for each unit. Additionally, the instrument air system consists of air dryers and a piping distribution system.

A.3.7.5 Incineration System

The tank vent stream is composed of primarily sweep gas and air purged through various in-process storage tanks that may contain small amounts of other gases such as ammonia and acid gas. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.7.6 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.7.7 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or fiber optics; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, ASU, and the coal handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical gas turbine, steam turbine, generator, and ASU control parameters.

A.3.7.8 Buildings

The plant has a central building housing the main control room, office, training, other administration areas and a warehouse/maintenance area. Other buildings are provided for water treatment equipment, coal handling, slurry preparation, and the MCCs. The buildings, are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment, as appropriate.

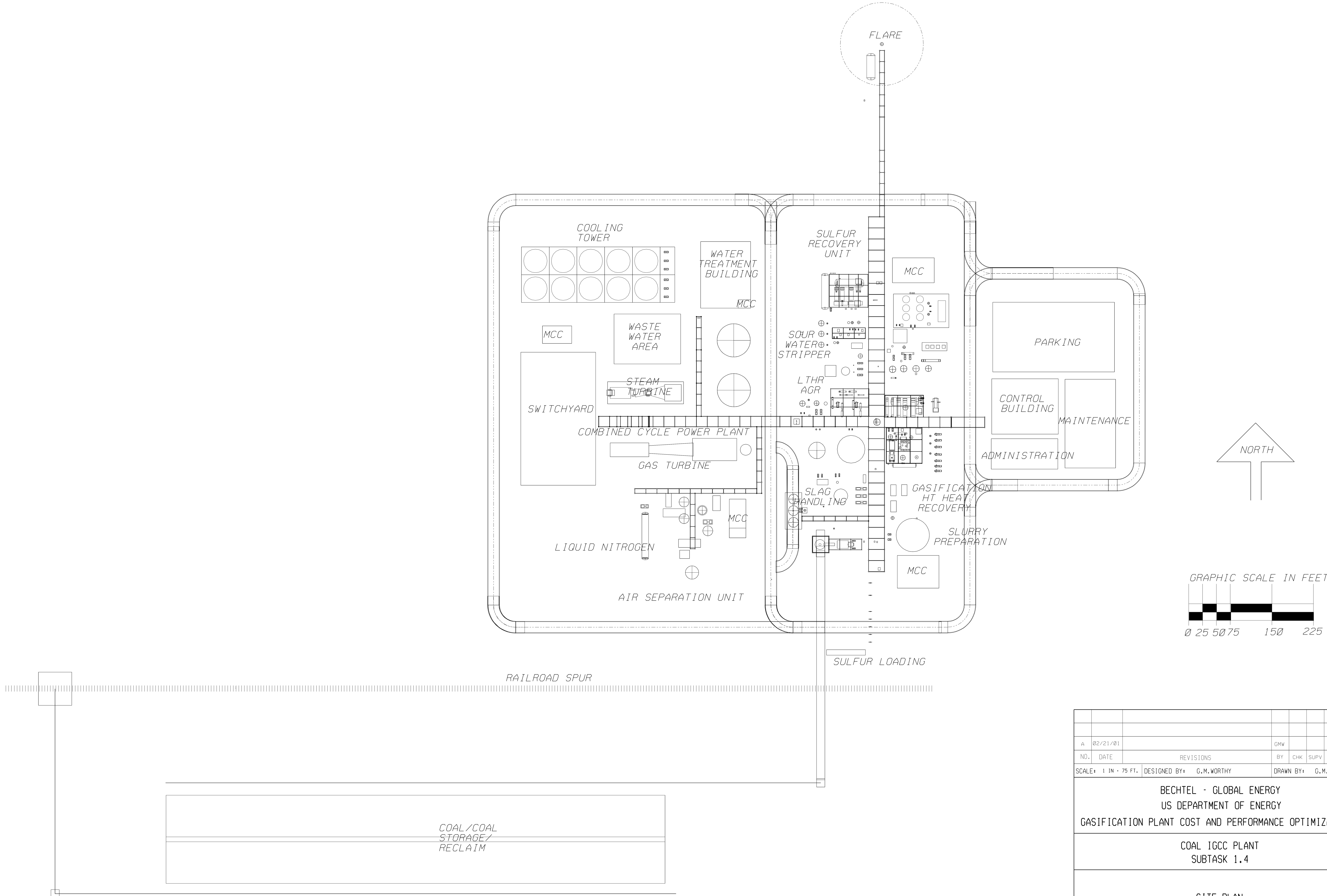
A.3.7.9 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the

Optimized Coal to Power IGCC Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A	Ø2/21/Ø1		GMW				

SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

COAL IGCC PLANT
SUBTASK 1.4

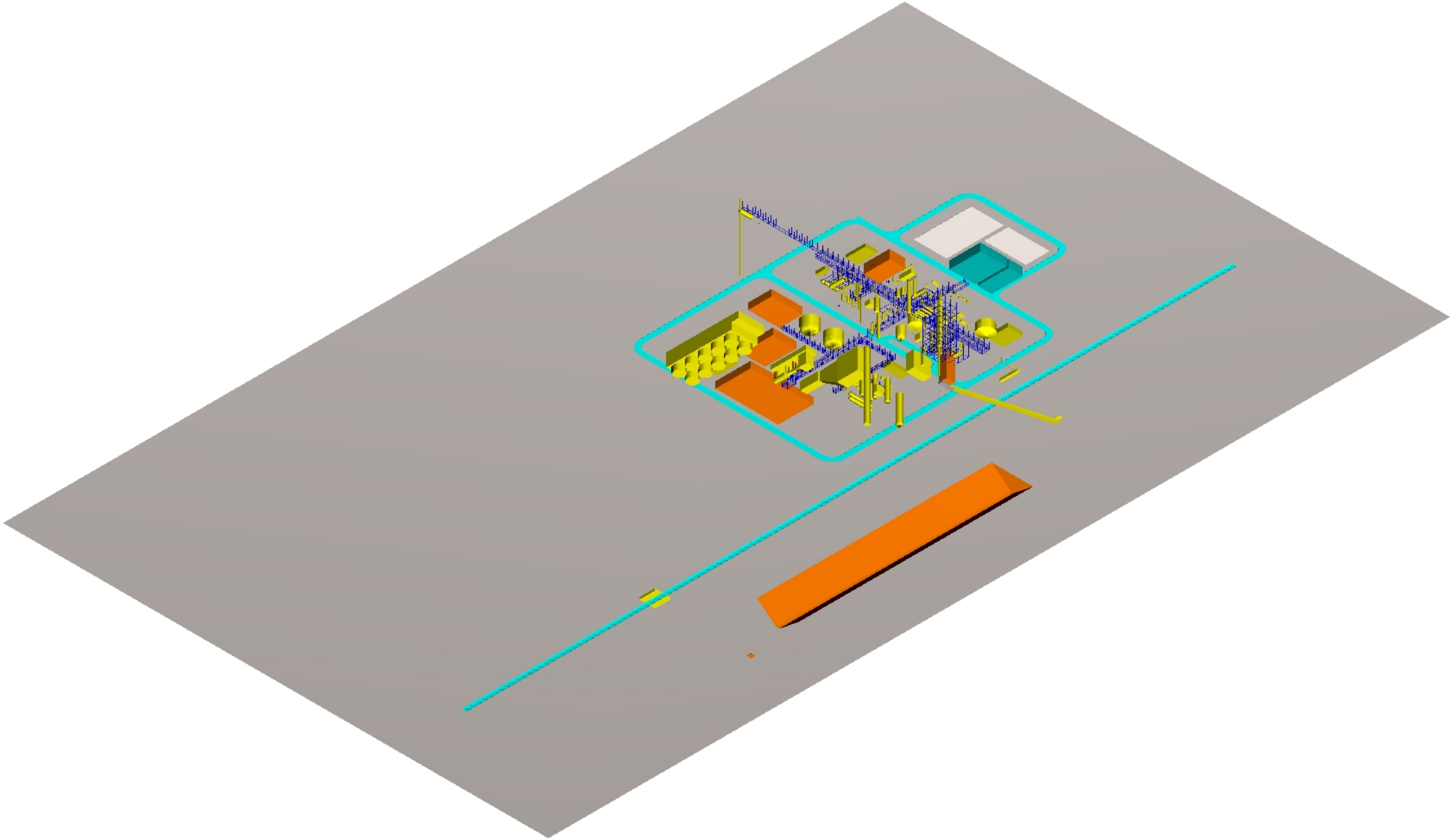
SITE PLAN

JOB NO: 24355-104 DRAWING NO: SK - ØØØ14 REV. A

Figure A3

Artist's Conception of the

Optimized Coal to Power IGCC Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, Optimized Coal to Power IGCC Plant Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 3,007 t/d of dry coal and produces 416.5 MWe of export electric power, 76.7 t/d of sulfur, and 462 t/d of slag (containing 15 wt% water). It also consumes 3,079 gpm of river water.

Figure A5 shows the overall water flow diagram for the plant. This figure provides details of the water usage and losses within the plant. No process water is dioscharged. The only waste water comes from the fresh water purification systems and cooling tower blowdown. The waste water discharge is about 700 gpm which includes an allowance of 150 gpm for rain water.

A.4.2 Performance Summary

Plant performance is based on the Coal to Power IGCC Plant configuration including an advanced "G/H-class" gas turbine. Global Energy provided a heat and material balance for these facilities using the design basis coal. This information was then integrated with a HRSG and reheat steam turbine. The GT Pro™ computer simulation program was used to simulate combined cycle performance and plant integration.[1]

Table A1 summarizes the overall performance of the Optimized Coal to Power IGCC Plant. As shown in the table, the oxygen input to the gasifiers is 2,294 t/d, and the heat input is 3,195 MMBtu/hr HHV. The gas turbine produces 300.1 MW of power from its generators. The steam turbine produces another 164.1 MW of power for a total power generation of 464.2 MW. Internal power usage consumes 47.7 MW leaving a net power production of 416.5 MW for export.

Table A2 summarizes the expected emissions from the Optimized Coal to Power IGCC Plant. The advanced "G/H-class" gas turbine and HRSG system has a stack exhaust flow rate of 4,816,970 lb/hr at 246°F. On a dry basis adjusted to 15% oxygen, these gases have a SOx concentration of 2.5 ppmv, a NOx concentration of 10 ppmv, and a CO concentration of 10 ppmv. The incinerator stack has an exhaust flow rate of 10,800 lb/hr at 653°F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 583 ppmv, a NOx concentration of 40 ppmv, and a CO concentration of 50 ppmv.

The plant emits 4,827,900 lbs/hr of total exhaust gases having an average SOx concentration of 4 ppmv, an average NOx concentration of 11 ppmv, and an average CO concentration of 11 ppmv. Expressed another way, this is 37 lb/hr of SOx (as SO_2), 74 lb/hr of NOx (as NO_2), and 45 lb/hr of CO. The sulfur removal is 99.7%.

[1] GT Pro is a registered trademark of the Thermoflow Corporation.

Table A1

Performance Summary of the Optimized Coal IGCC Coproduction Plant

Ambient Temperature, °F	59
Coal Feed, as received, TPD	3,517
Dry Coal Feed to Gasifiers, TPD	3,007
Total Fresh Water Consumption, gpm	3,079
Sulfur, TPD	76.7
Slag Produced, TPD (15% moisture)	462
Solid Waste (salts) to Disposal, TPD	3.0
Total Oxygen Feed to the Gasifier, TPD of 95% O_2	2,294
Heat Input to the Gasifier (HHV), Btu/hr x 10^6	3,195
Cold Gas Efficiency at the Gas Turbine (HHV), %	80.8
Fuel Input to Gas Turbine, lb/hr	543,793
Heat Input to Gas Turbine (LHV), Btu/hr x 10^6	2,427
Nitrogen Injection to Gas Turbine, lb/hr	620,122
Gas Turbines Output, MW	300.1
Steam Turbine Output, MW	164.1
Gross Power Output, MW	464.2
Gasification Plant Power Consumption, MW	(11.5)
ASU Power Consumption, MW	(23.9)
Balance of Plant & Auxiliary Load Power Consumption, MW	(12.3)
Net Power Output, MW	416.5

Table A2

Environmental Emissions Summary*
of the Optimized Coal to Power IGCC Plant

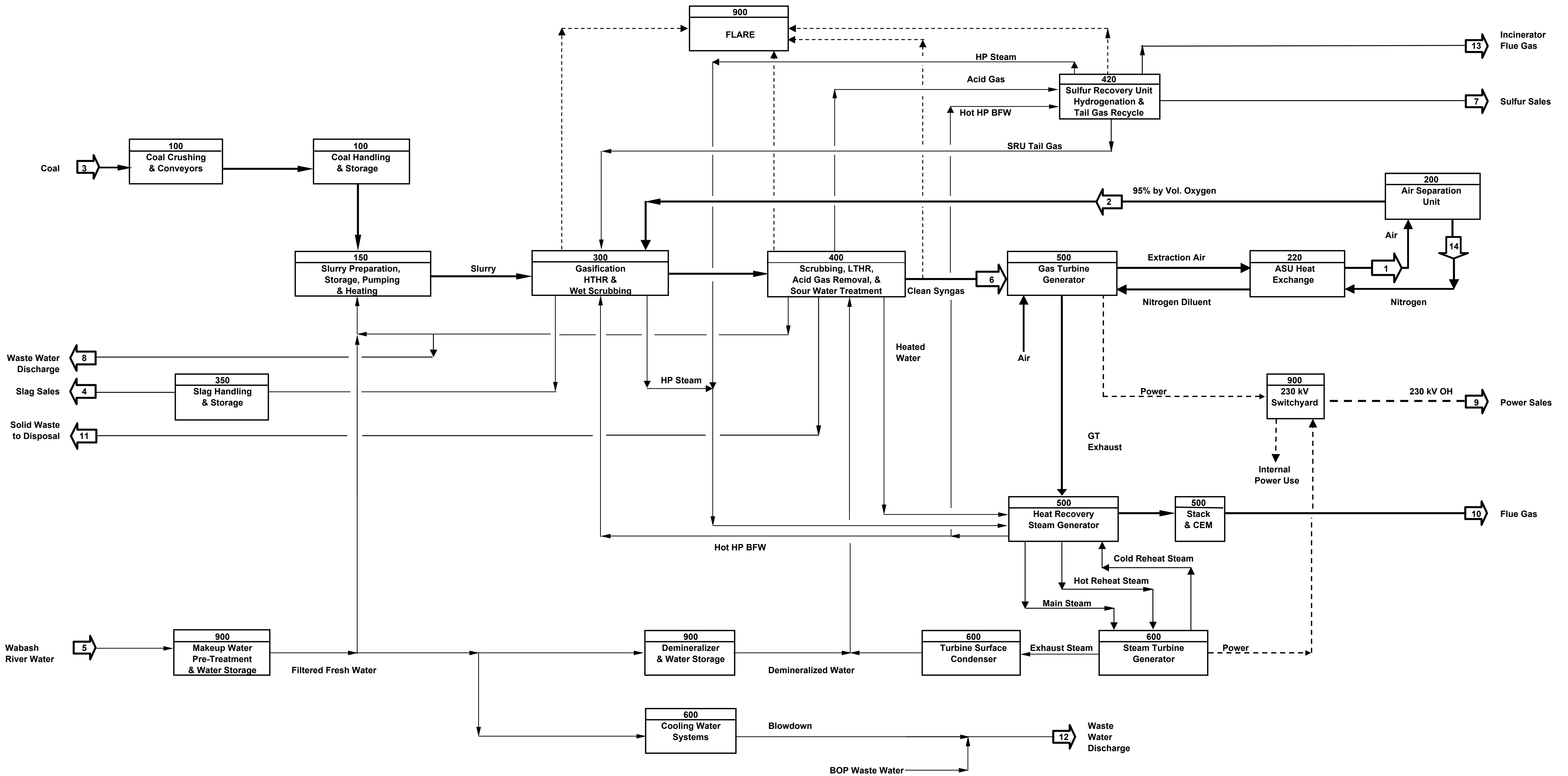
<u>Total Gas Turbine Emissions</u>	
GT/HRSG Stack Exhaust Flow Rate, lb/hr	4,817,100
GT/HRSG Stack Exhaust Temperature, °F	246
Emissions (at 15% oxygen, dry basis)	
SO×, ppmvd	2.4
SO× as SO_2, lb/hr	25
NO×, ppmvd	10
NO× as NO_2, lb/hr	127
CO, ppmvd	10
CO, lbl/hr	47
<u>Incinerator Emissions</u>	
Stack Exhaust Flow Rate, lb/hr	10,800
Stack Exhaust Temperature, °F	653
Emissions (at 3% oxygen, dry basis)	
SO×, ppmvd	583
SO× as SO_2, lb/hr	11.5
NO×, ppmvd	40
NO× as NO_2, lb/hr	0.3
CO, ppmvd	50
CO, lbl/hr	0.5
<u>Total Plant Emissions</u>	
Exhaust Flow Rate, lb/hr	4,827,900
Emissions	
SO×, ppmvd	4
SO× as SO_2, lb/hr	37
NO×, ppmvd	18
NO× as NO_2, lb/hr	127
CO, ppmvd	11
CO, lbl/hr	47
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	99.7

* Expected emissions performance

Figure A4

Detailed Block Flow Diagram of the

Optimized Coal to Power IGCC Plant



See Figure A5 for a water flow diagram.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 10,004 Tons/Day	Oxygen 2,294 Tons/Day	Coal 3,007 Tons/Day	Slag 462 Tons/Day	Water 1,539,500 GPM	Syngas 543,793 Lb/Hr	Sulfur 76.7 Tons/Day	Water 0 Lb/Hr	Power 416,500 kWe	Flue Gas 4,817,000 Lb/Hr	Waste 3 Tons/Day	Water 351,500 Lb/Hr	Flue Gas 10,800 Lb/Hr	Nitrogen 620,122 Lb/Hr							
Nominal Pressure - psig	---	718	NA	NA	50	435	NA	NA	NA	Atmos.	Atmos.	Atmos.	Atmos.	---							
Temperature - F	221	240	NA	NA	70	552	NA	NA	NA	237	NA	71	500	80							
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,746	NA	NA	NA	NA	NA	NA	NA	NA							
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,463	NA	NA	NA	NA	NA	NA	NA	NA							
Energy - MM HHV/Hr	NA	NA	3,195	NA	NA	2,581	NA	NA	NA	NA	NA	NA	NA	NA							
Energy - MM LHV/Hr	NA	NA	3,076	NA	NA	2,427	NA	NA	NA	NA	NA	NA	NA	NA							
Notes	Dry Basis	2164 O2	Dry Basis	15%Wtr.	3,079 GPM	to GT	Sales	0 GPM	230 kV		Solids	703 GPM									

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.4

OPTIMIZED COAL IGCC POWER PLANT

BLOCK FLOW DIAGRAM

File: Fig A4 1.4 R1.xls

February 21, 2002

Figure A5

Overall Water Flow Diagram of the

Optimized Coal to Power IGCC Plant

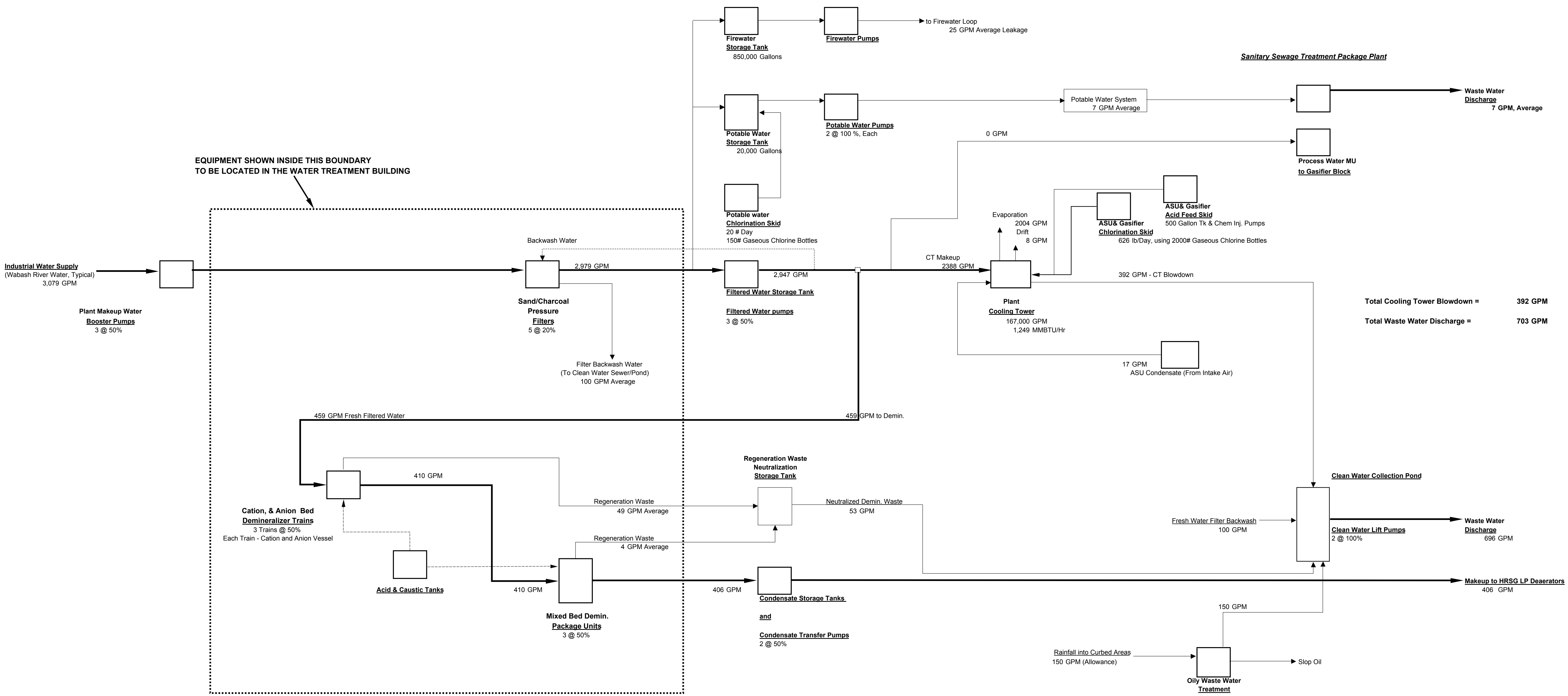


Figure A5

SUBTASK 1.4

Optimized Coal IGCC Power Plant

Water Flow Diagram

File: Fig A5 1.4 R1.xls

February 21, 2002

A.5 Major Equipment List

Table A3 lists the major pieces of equipment and systems by process area in the Optimized Coal to Power IGCC Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit, are not available.

Table A3
Equipment List for the Subtask 1.4 Coal IGCC Power Plant

Fuel Handling – 100
Unit Train Rail Loop
Rotary Coal Car Dumper
Rotary Car Dumper Coal Pit
Rotary Dumper Vibratory Feeders
Rotary Dumper Building & Coal Handling Control Control/Electrical Rooms
Rotary Car Dumper Dust Collector
Rotary Car Dumper Sump Pumps
Coal Car Unloading Conveyor
Coal Crusher
Reclaim Coal Grizzly
Coal Storage Dome
Reclaim Conveyors
Storage/Feed Bins
Reclaim Pit Sump Pumps
Coal Dust Suppression System
Coal Handling Electrical Equipment and Distribution
Electric Hoist
Metal Detector
Magnetic Separator
Vibrating Feeder
Slurry Preparation – 150
Weigh Belt Feeder
Rod Charger
Rod Mill
Rod Mill Product Tank
Rod Mill Product Tank Agitator
Rod Mill Product Pumps
Recycle Water Storage Tank
Recycle Water Pumps
Slurry Storage Tank
Slurry Storage Tank Agitator
Slurry Recirculation Pumps
Solids Recycle Tank
Solids Recycle Tank Agitator
Solids Recycle Pumps
Rod Mill Lube Oil Pumps
Slurry Feed Pumps

Table A3 (Continued)

Equipment List for the Subtask 1.4 Coal IGCC Power Plant

ASU – 200
Air Separation Unit including:
Nitrogen Compressor
Air Scrubber
Oxygen Compressor
Cold Box (Main Exchanger)
High Temperature Air / Nitrogen Heat Exchanger
Liquid Nitrogen Storage
Gasification - 300
First Stage Mixer
Second Stage Mixer
Gasifier
Post Reactor Residence Vessel
High Temperature Heat Recovery Unit
Hot Cyclone Separator
Slag Pre-Crushers
Slag Crushers
Reactor Nozzle Cooling Pumps
Crusher Seal Water Pumps
Syngas Desuperheater
Nitrogen Heater
Pressure Reduction Units
Dry Char Filters
Cyclone Solids Pickup Vessel
Filter Solids Pickup Vessel
Syngas Scrubber Column
Syngas Scrubber Recycle Pumps
Slag Handling – 350
Slag Dewatering Bins
Slag Gravity Settler
Slag Water Tank
Slag Water Pumps
Gravity Settler Bottoms Pumps
Slag Recycle Water Tank
Slag Feedwater Quench Pumps
Slag Water Recirculation Pumps
Polymer Pumps
Slag Recycle Water Cooler

Table A3 (Continued)

Equipment List for the Subtask 1.4 Coal IGCC Power Plant

LTHR/AGR – 400
Syngas Recycle Compressor
Syngas Recycle Compressor K. O. Drum
Syngas Heater
COS Hydrolysis Unit
Amine Reboiler
Sour Water Condenser
Sour Gas Condensate Condenser
Sour Gas CTW Condenser
Sour Water Level Control Drum
Sour Water Receiver
Sour Gas K.O. Drum
Sour Water Carbon Filter
MDEA Storage Tank
Lean Amine Pumps
Acid Gas Absorber
MDEA Cross-Exchangers
MDEA CTW Coolers
MDEA Carbon Bed
MDEA Post-Filter
Acid Gas Stripper
Acid Gas Stripper Recirculation Cooler
Acid Gas Stripper Reflux Drum
Acid Gas Stripper Quench Pumps
Acid Gas Stripper Reboiler
Acid Gas Stripper Overhead Filter
Lean MDEA Transfer Pumps
Acid Gas Stripper K.O. Drum
Acid Gas Stripper Preheater
Amine Reclaim Unit
Condensate Degassing Column
Degassing Column Bottoms Cooler
Sour Water Transfer Pumps
Ammonia Stripper
Ammonia Stripper Bottoms Cooler
Stripped Water Transfer Pumps
Quench Column
Quench Column Bottoms Cooler
Stripped Water Transfer Pumps
Degassing Column Reboiler
Ammonia Stripper Reboiler
Syngas Heater
Syngas Moisturizer
Moisturizer Recirculation Pumps
Reverse Osmosis Unit for Chloride Removal
Zero Liquid Discharge Water Evaporation System

Table A3 (Continued)

Equipment List for the Subtask 1.4 Coal IGCC Power Plant

Sulfur Recovery – 420
Reaction Furnace/Waste Heat Boiler
Condensate Flash Drum
Sulfur Storage Tank
Storage Tank Heaters
Sulfur Pump
Claus First Stage Reactor
Claus First Stage Heater
Claus First Stage Condenser
Claus Second Stage Reactor
Claus Second Stage Heater
Claus Second Stage Condenser
Condensate Level Drum
Hydrogenation Gas Heater
Hydrogenation Reactor
Quench Column
Quench Column Pumps
Quench Column Cooler
Quench Strainer
Quench Filter
Tail Gas Recycle Compressor
Tail Gas Recycle Compressor Intercooler
Tank Vent Blower
Tank Vent Combustion Air Blower
Tank Vent Incinerator/Waste Heat Boiler
Tank Vent Incinerator Stack
GT / HRSG – 500
Gas Turbine Generator (GTG), Advanced “G/H-class” Dual Fuel (Gas and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.
GTG Erection (S/C)
Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, with Integral Deaerator
HRSG Stack (S/C)
HRSG Continuous Emissions Monitoring Equipment
HRSG Feedwater Pumps
HRSG Blowdown Flash Tank
HRSG Atmospheric Flash Tank
HRSG Oxygen Scavenger Chemical Injection Skid
HRSG pH Control Chemical Injection Skid
GTG Iso-phase Bus Duct
GTG Synch Breaker
Power Block Auxiliary Power XformerS

Table A3 (Continued)

Equipment List for the Subtask 1.4 Coal IGCC Power Plant

Steam Turbine Generator & Auxilaries - 600
Steam Turbine Generator (STG), Reheat, TC2F, complete with Lube Oil Console
Steam Surface Condenser, 316L tubes
Condensate (hotwell) pumps
Circulating Water Pumps
Auxiliary Cooling Water Pumps
Cooling Tower
Balance Of Plant - 900
High Voltage Electrical Switch Yard (S/C)
Common Onsite Electrical and I/C Distribution
DCS
In-Plant Communication System
15KV, 5KV and 600V Switchgear
BOP Electrical Devices
Power Transformers
Motor Control Centers
River Water - Makeup Water Intake and Plant Supply Pipeline
Water Intake System S/C Including;
Intake Structure
Pumphouse
Makeup Pumps
Substation & MCC
Lighting, Heating & Ventilation
Makeup Water Treatment Storage and Distribution
Water Treatment Building Equipment
Hydroclone Clarifier
Coagulation Storage Silo
Clarifier Lime Storage Silo
Gravity Filter
Clear Well
Clear Well Water Pumps
Water Softner Skids
Carbon Filters
Cation Demineralizer Skids
Degasifiers
Anion Demineralizer Skids
Demineralizer Polishing Bed Skids
Bulk Acid Tank
Acid Transfer Pumps
Demineralizer - Acid Day Tank Skid
Bulk Caustic Tank Skid
Caustic Transfer Pumps

Table A3 (Continued)

Equipment List for the Subtask 1.4 Coal IGCC Power Plant

Balance of Plant – 900 (Continued)
Demineralizer - Caustic Day Tank Skid
Firewater Pump Skids
Waste Water Collection and Treatment
Oily Waste - API Separator
Oily Waste - Dissolved Air Flotation
Oily Waste Storage Tank
Sanitary Sewage Treatment Plant
Wastewater Storage Tanks
Waste Water Outfall
Monitoring Equipment
Common Mechanical Systems
Shop Fabricated Tanks
Miscellaneous Horizontal Pumps
Auxiliary Boiler
Safety Shower System
Flare
Flare K.O. Drum
Flare K.O. Drum Pumps
Chemical Feed Pumps
Chemical Storage Tanks
Chemical Storage Equipment
Laboratory Equipment

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.4 scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 40 months which includes three months of performance testing before full commercial operation. Notice to proceed is based on a confirmed Mid-West plant site and the availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor, and air separation unit.

The project construction schedule of the Optimized Coal to Power IGCC Plant was developed by examining that of the Wabash River Repowering Project and correcting for several problems that were encountered during construction. Furthermore, construction experts were included in the Value Improving Practices team that developed the plant layout so that both ease of construction and maintenance were considered.

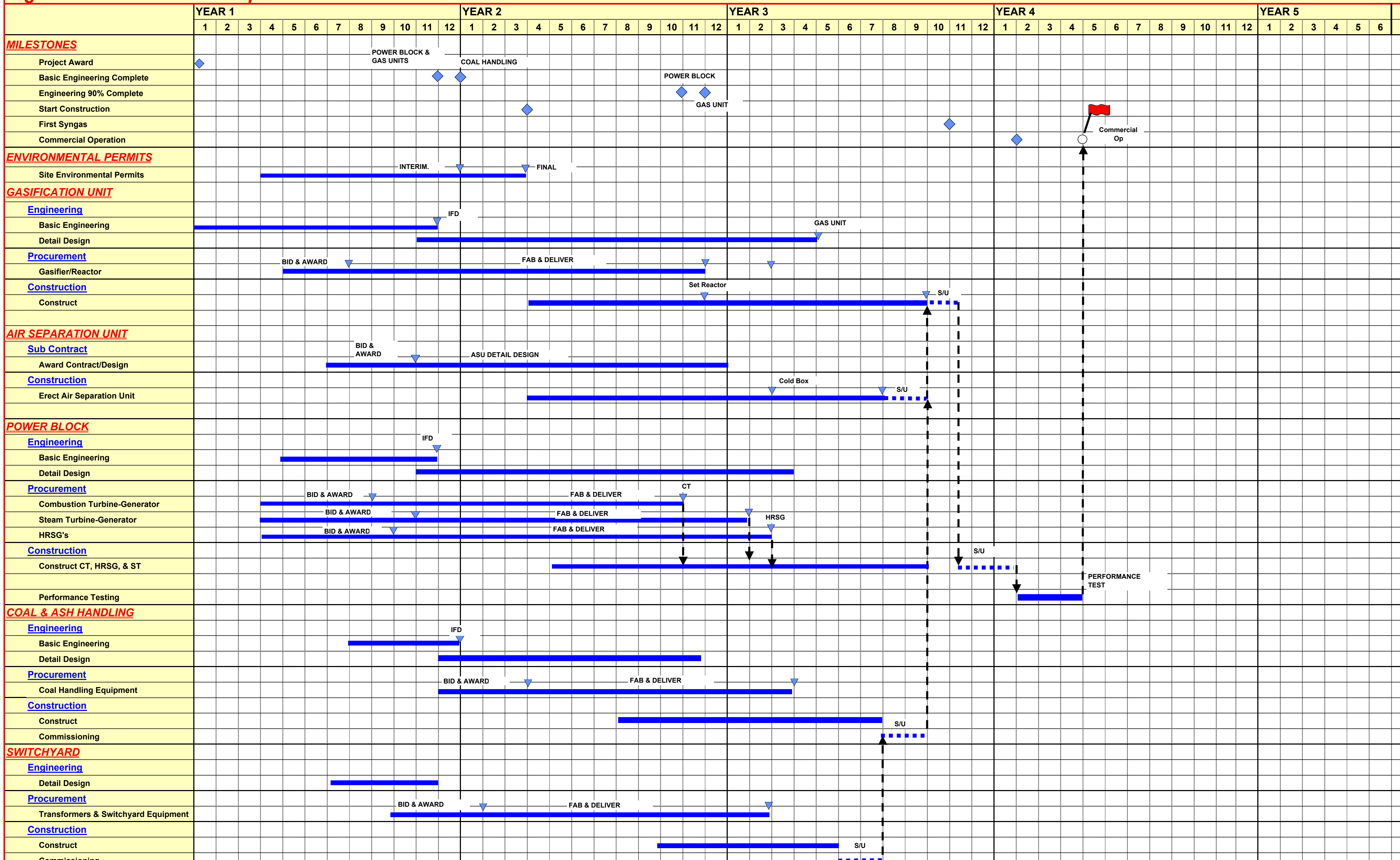
The milestone construction schedule for the major process blocks of the Optimized Coal to Power IGCC Plant is shown in Figure A6.

Figure A6

Milestone Construction Schedule for

the Optimized Coal to Power IGCC Plant

Figure A6 - Subtask 1.4 - Optimized Coal to Power IGCC Plant



BY	DATE	REV.
NS	9/7/01	A+++
SJK	8/6/01	A++
SJK	5/10/01	A+
TM	5/1/01	A

Bechtel
Houston, Texas

US DEPARTMENT OF ENERGY
Gasification Plant Cost & Performance Optimization
Subtask 1.4 Optimized Coal to Power IGCC Plant
Milestone Schedule

A.6.2 Capital Cost Summary

A.6.2.1. General

The following table illustrates the work breakdown structure (WBS) for Subtask 1.4 and the source of the cost information for each of the areas. The WBS for Subtask 1.4 is the same as that which was used for Subtasks 1.2 and 1.3.

WBS	Description	Subtask 1.4
100	Solid Fuel Handling	Bechtel Engineering to provide scope and estimate
150	Slurry Preparation	Adjusted Wabash River and selected quotes
200	Air Separation Unit	Praxair Quote
300	Gasification	Adjusted Wabash River and selected quotes
350	Slag Handling	Adjusted Wabash River
400	Sulfur Removal	Adjusted Wabash River and selected quotes
420	Sulfur Recovery	Adjusted Wabash River and selected quotes
500	GT/HRSG	Based on Bechtel's Powerline^{TM} design and cost information
600	Steam Turbine & Auxiliary Equipment	Based on Bechtel's Powerline^{TM} design and cost information
900	Balance Of Plant	
	High Voltage Switchyard	Bechtel Engineering to provide scope and estimate
	Makeup Water Intake	Bechtel Engineering to provide scope and estimate
	Makeup Water Treatment System	Bechtel Engineering to provide scope and estimate
	Waste Water Collection System	Bechtel Engineering to provide scope and estimate
	Waste Water Discharge	Bechtel Engineering to provide scope and estimate
	Solids Discharge	Used catalyst and waste to landfill
	Piping	By Comet model as calibrated to Wabash River
	Concrete, Steel and Architecture	Wabash River / PSI adjusted for technical basis
	Common Electrical and I&C Systems	Based on Wabash River adjusted for technical basis

Vendor quotes were obtained for most of the new and high price equipment in Subtask 1.4. The power block cost estimate is based on an expected price for the advanced "G/H-class" gas turbine and Bechtel Powerline^{TM} cost for similar sized power plant currently under construction on the Gulf Coast. Thus, compared to Subtasks 1.1 and 1.2, a much smaller part of the plant costs were estimated based on the Wabash River facility and adjusted for inflation. Mid-West union mid-year 2000 labor rates were used, the same labor rate as was used for Subtask 1.1 so that this cost estimate is comparable.

This cost estimate is an instantaneous mid-year 2000 cost estimate based on market pricing. There is no forward escalation. As such, it reflects any aberrations in equipment costs based on current market conditions. For example, there is a large demand and backlog for gas turbines so that the current price seems high based on historical data.

Major Equipment

Major equipment from Subtasks 1.1, 1.2, and 1.3 was loaded into a data base and modified to reflect the scope of Subtask 1.4. Modifications include changes in equipment duty (as a result of both capacity changes and the Design-to-Capacity VIP), quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

The Design-to-Capacity and Classes of Plant Quality Value Improving Practices were considered in sizing the equipment for this plant. Because coal compositions can be quite variable, a range of coals were considered in the design of the Wabash River Repowering Project to provide feedstock flexibility. In Subtask 1.4, this overdesign was eliminated. Furthermore, some equipment was redesigned to reflect current engineering design practices.

Bulk Materials

Wabash River Repowering Project bulk commodity quantity estimates for steel, concrete, and piping were used as the basis, and then the quantities were adjusted to reflect the scope and site plan for this subtask. Current pricing was used to estimate the costs for the bulk material items.

Subcontracts

Supply and install subcontract pricing was estimated for:

By Budget Quote
- Coal Handling
- Field Erected Tanks
- Air Separation Unit
- Cooling Tower (except basin)

By Unit Pricing
- Buildings including interior finish, HVAC, and Furnishings
- Fire Protection Systems
- Site Development
- Rail Spur

From the Wabash River Facility
- Painting and Insulation
- 230 KV Switchyead
- Gasifier Refractory
- Start-up Services; i.e., flushes and steam blows

Construction

Labor is based on mid-year 2000 Mid-West union shop rates and historic productivity factors. Union labor is used for refractory installation.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.4. Power block costs are based on Bechtel's Powerline™ design and current cost information.

Material Take-off

Subtask 1.1 quantities were used as the basis and adjusted to reflect the scope and site plan for Subtask 1.4, as was done for Subtasks 1.2 and 1.3. Modifications were made, as necessary. Concrete, steel and instrumentation were adjusted on an area by area basis reflecting the increased numbers of process trains. The basis for piping adjustment was developed from quantities generated by the COMET model. Electrical quantities were manually adjusted for this subtask.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Design criteria basis are the codes, standards, laws and regulations to be compliant with U. S. and local codes for the designated region typical for U. S. installations and for the designated location of the plant.
- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000. Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- For new and highly priced equipment, current vendor quotes were obtained to reflect current market pricing.
- Site Conditions:
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Coal is delivered by rail on the north side of the site
- Cost includes only areas within the site plan
- Critical spares are included; e.g., proprietary items, one-of-a-kind items, and long lead time items. Normal warehouse, operational, and commissioning/start-up spares are excluded.
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)

The following costs are excluded:

- Contingency and risks
- Cost of permits
- Taxes
- Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
- Facilities external to the site in support of the plant
- Licensing fees
- Agent fees
- Initial fill of chemicals

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Optimized Coal to Power IGCC Plant.

Table A4

Capital Cost Summary of the Optimized Coal to Power IGCC Plant

Plant Area	Direct Field Material			
Solids Handling	8,912,000	7,859,000	467,000	17,238,000
Air Separation Unit	32,855,000	21,837,000	1,472,000	56,164,000
Gasification	93,684,000	47,078,000	23,424,000	164,185,000
Power Block	134,157,000	21,588,000	16,152,000	171,897,000
Balance Of Plant	32,017,000	20,500,000	2,655,000	55,171,000
Total	301,625,000	118,862,000	44,169,000	464,656,000

Note: Because of rounding, some columns may not add to the total that is shown.

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±15%. The level of accuracy reflects a high degree of confidence based on the large number of vendor quotes that were obtained and that the power block costs are based on a current similar Gulf Coast power project. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

Appendix E

Subtask 1.4 (Appendix B)

Financial Model Analysis Input

Subtask 1.4 (Appendix B)

Financial Analysis Model Input

Bechtel Technology and Consulting (now Nexant) developed the DCF financial model as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task.[1] This model performs a discounted cash flow financial analysis to calculate investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data directly related to the specific plant as follows.

Data on the Plant Input Sheet

- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table B1 contains the data that are entered on the Plant Input Sheet for the Subtask 1.7 Coal to Hydrogen Plant.

The Scenario Input Sheet primarily contains data that are related to the general economic environment that is associated with the plant. In addition, it also contains some data that are plant related. The data on the Scenario Input Sheet are shown below.

Data on the Scenario Input Sheet

- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Start up information

Table B2 contains the base case data that are entered on the Scenario Input Sheet for the Subtask 1.7 Coal to Hydrogen Plant.

[1] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Table B1
Plant Input Sheet Data for Subtask 1.4

Project Inputs	**Case A**	**Case B**
Project Summary Data		
Project Name / Description	Subtask 1.4 w/o Gas Backup	Subtask 1.4 WITH Gas Backup
Project Location	Midwest	Midwest
Project Type/Structure	BOO	BOO
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs	Multiple Outputs
Fuel Type (**Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Petroleum Coke	Petroleum Coke
Plant Input/Output Flowrates - Daily Average Basis (Calendar Day)		
Syngas Capacity (MMscf/day) - Optional		
Gross Electric Power Capacity (MW) - Optional	464.2	464.2
Net Electric Power Capacity (MW)	332.4	387.8
Steam Capacity (Tons/hr)	0.0	0.0
Hydrogen Capacity (MMscf/day)	0.0	0.0
Carbon Monoxide Capacity (MMscf/day) - PSA Tail Gas (Low Btu Fuel Gas)	0.0	0.0
Elemental Sulfur (Tons/day)	61.2	61.2
Slag Ash (Tons/day)	368.7	368.7
Fuel (Tons/day) - **COAL**	2,400.1	2,400.1
Chemicals - **Natural Gas (Mscf/day) - INPUT**	0	-8,896
Environmental Credit (Tons/day)	0	0
Other (Tons/day) - Flux - **INPUT**	0	0
Operating Hours per Year	8,760	8,760
Guaranteed Availability (percentage)	100.0%	100.0%
Enter One of the Following Items Depending on Project Type:		
Heat Rate (Btu/kWh) based on HHV - Required for power projects		
Annual Fuel Consumption (in MMcf or Thousand Tons) - Required for non-power projects	876.0	876.0
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)		
EPC (in thousand dollars)	464,656	464,656
Owner's Contingency (% of EPC Costs)	5.0%	5.0%
Development Fee (% of EPC Costs)	1.23%	1.23%
Start-up (% of EPC Costs)	1.50%	1.50%
Owner's Cost (in thousand dollars) - Land	$200	$200
Additional Capital Cost - Spares	$6,970	$6,970
Additional Cost #1 - Duties, Taxes, Insurance, etc.	$1,650	$1,650
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent -To be verified during project development. (in thousand dollars)	$23,233	$23,233
Operating Costs and Expenses		
Variable O&M (% of EPC Cost) - **HIGHLY CONFIDENTIAL**		
Fixed O&M Cost (% of EPC Cost) - Staffing - **HIGHLY CONFIDENTIAL**		
Additional Comments: When the average daily input and output flow rates, as calculated by the availability analysis, are supplied, the guaranteed plant availability should be set to 100.0%.	Subtask 1.4 - Optimized Coal to Power IGCC Plant w/o Natural Gas - 7/18/01	Subtask 1.4 - Optimized Coal to Power IGCC Plant WITH Natural Gas - 7/29/01

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 1 of 5)

Project Name / Description	Subtask 1.4 w/o Gas Backup	Subtask 1.4 WITH Gas Backup
Project Location	Midwest	Midwest
Project Type/Structure	BOO	BOO

Capital Structure		
Percentage Debt	80%	80%
Percentage Equity	20%	20%
Total Debt Amount (in thousand dollars) - **CALCULATED**	---	---

Project Debt Terms		
Loan 1: Senior Debt		
% of Total Project Debt **(total for Loans 1,2, and 3 must = 100%)**	100%	100%
Loan Amount (in thousand dollars) - **CALCULATED**	---	---
Interest Rate	10%	10%
Financing Fee	3%	3%
Repayment Term (in Years)	15	15
Grace Period on Principal Repayment	0	0
First Year of Principal Repayment	2003	2003
Loan 2: Subordinated Debt		
% of Total Project Debt	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0
Interest Rate	8%	8%
Financing Fee	3%	3%
Repayment Term (in Years)	15	15
Grace Period on Principal Repayment	1	1
First Year of Principal Repayment	2004	2004
Loan 3: Subordinated Debt		
% of Total Project Debt	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0
Interest Rate	7%	7%
Financing Fee	3%	3%
Repayment Term (in Years)	10	10
Grace Period on Principal Repayment	1	1
First Year of Principal Repayment	2004	2004

Loan Covenant Assumptions		
Interest Rate for Debt Reserve Fund (DRF)	5%	5%
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	Yes	Yes
Percentage of Total Debt Service used as DRF	20%	20%

Depreciation		
Construction (Years)	7	7
Financing (Years)	7	7

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 2 of 5)

Working Capital		
Days Receivable	30	30
Days Payable	30	30
Annual Operating Cash (in thousand dollars)	100	100
Initial Working Capital (% of first year revenues)	0%	0%

ECONOMIC ASSUMPTIONS

Cash Flow Analysis Period		
Plant Economic Life/Concession Length (in Years)	20	20
Discount Rate	12%	12%

Escalation Factors		
Project Output/Tariff		
Syngas	1.7%	1.7%
Electricity: Capacity Payment	1.7%	1.7%
Electricity: Energy Payment	1.7%	1.7%
Steam	3.1%	3.1%
Hydrogen	3.1%	3.1%
Carbon Monoxide	1.7%	1.7%
Elemental Sulfur	0.0%	0.0%
Slag Ash	0.0%	0.0%
Fuel (IGCC output)	0.0%	0.0%
Chemicals - **Natural Gas**	3.9%	3.9%
Environmental Credit	1.7%	1.7%
Other **- Flux**	1.7%	1.7%
Fuel/Feedstock		
Gas	3.9%	3.9%
Coal	1.2%	1.2%
Petroleum Coke - **Used for COAL in Petroleum Coke Option**	1.2%	1.2%
Other/Waste	2.3%	2.3%
Operating Expenses and Construction Items		
Variable O&M	2.3%	2.3%
Fixed O&M	2.3%	2.3%
Other Non-fuel Expenses	2.3%	2.3%

Tax Assumptions		
Tax Holiday (in Years)	0	0
Income Tax Rate	40%	40%
Subsidized Tax Rate (used as investment incentive)	0%	0%
Length of Subsidized Tax Period (in Years)	0	0

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 3 of 5)

FUEL/FEEDSTOCK ASSUMPTIONS

Fuel Price		
Gas ($/Mcf)	2.60	2.60
Coal ($/Ton)	22.0	22.0
Petroleum Coke ($/ton) - **Used for COAL in Petroleum Coke Option**	22.0	22.0
Other/Waste ($/Ton)	14.00	14.00

Heating Value Assumptions		
HHV of Natural Gas (Btu/cf)	1,000	1,000
HHV of Coal (Btu/kg)	28,106	28,106
HHV of Petroleum Coke (Btu/kg), Dry basis **- Used for Coal**	28,106	28,106
HHV of Other/Waste (Btu/kg)	0	0

TARIFF ASSUMPTIONS

INITIAL TARIFF LEVEL (In Dollars in the first year of construction)		
Syngas ($/Mcf)	$0	$0
Capacity Payment (Thousand $/MW/Year)	$0	$0
Electricity Payment ($/MWh)	$27.00	$27.00
Steam ($/Ton)	$5.60	$5.60
Hydrogen ($/Mcf)	$1.30	$1.30
Carbon Monoxide ($/Mcf)	$0.2274	$0.2274
Elemental Sulfur ($/Ton)	$30.00	$30.00
Slag Ash ($/Ton)	$0	$0
Fuel ($/Ton)	$0	$0
Chemicals **- Natural Gas ($/Mscf)**	$2.60	$2.60
Environmental Credit ($/Ton)	$0	$0
Other ($/Ton) - **Flux**	$5.00	$5.00

CONSTRUCTION ASSUMPTIONS

Construction Schedule		
Construction Start Date	#NAME?	#NAME?
Construction Period (in months) - Maximum of 48	40	40
Plant Start-up Date *(must start on January 1)*	1/1/2003	1/1/2003

Percentage Breakout of Cost over Construction Period (each category must total 100%)		
Year 1		
EPC Costs - See Note 1.	6.82%	6.82%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	0%	0%
Start-up Costs	0%	0%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	70%	70%
Additional Capital Costs - Spares	0%	0%
Financing Fee	0%	0%

Table B2
Scenario Input Sheet Data for Subtask 1.4

Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	6.82%	6.82%
Year 2		
EPC Costs - See Note 1.	36.00%	36.00%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	100%	100%
Start-up Costs	0%	0%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	30%	30%
Additional Capital Costs - Spares	0%	0%
Financing Fee	100%	100%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	36.00%	36.00%
Year 3		
EPC Costs - See Note 1.	31.81%	31.81%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	0%	0%
Start-up Costs	30%	30%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	0%	0%
Additional Capital Costs - Spares	0%	0%
Financing Fee	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	31.81%	31.81%
Year 4		
EPC Costs - See Note 1.	27.37%	27.37%
Initial Working Capital	100%	100%
Owner's Contingency	100%	100%
Development Fee	0%	0%
Start-up Costs	70%	70%
Initial Debt Reserve Fund	100%	100%
Owner's Cost - Land	0%	0%
Additional Capital Costs - Spares	100%	100%
Financing Fee	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	27.37%	27.37%

Table B2
Scenario Input Sheet Data for Subtask 1.4

Plant Ramp-up Option (Yes or No)	Yes	Yes

Start-Up Operations Assumptions (% of Full Capacity)		
Year 1, First Quarter	25.0%	25.0%
Year 1, Second Quarter	50.0%	50.0%
Year 1, Third Quarter	75.0%	75.0%
Year 1, Fourth Quarter	90.0%	90.0%
Year 1 Average Capacity %	60.0%	60.0%
Year 2, First Quarter	100.0%	100.0%
Year 2, Second Quarter	100.0%	100.0%
Year 2, Third Quarter	100.0%	100.0%
Year 2, Fourth Quarter	100.0%	100.0%
Year 2 Average Capacity %	100.0%	100.0%

CONVERSION FACTORS	
kJ to Btu	0.94783
Btu to kWh	3,413
kg to English Ton	1,016
kW per MW	1,000
kJ/kWh	3,600
Gallons Equivalent to 1 Barrel of Crude Oil	42
Cubic Feet to Cubic Meter	0.02832
Months per Year	12
Hours per Day	24
10^6 (for conversion purposes)	1,000,000
Hours per year	8,760

Note 1. The total is greater than 100% to account for inflation during construction.

44 Montgomery Street, Suite 4100
San Francisco, CA 94104-4814
tel: +1 415 912 2100
fax: +1 415 981 9744
email: info@nexant.com

www.nexant.com

Prepared for:
United States
Department of Energy
National Energy
Technology Laboratory
Contract No. DE-AC26-99FT40342

Gasification Plant Cost and Performance Optimization

Task 1 Topical Report
IGCC Plant Cost Optimization

Volume 3
Appendices F though L

Submitted By:

MAY 2002

U. S. Department of Energy
National Energy Technology Laboratory (NETL)

Gasification Plant Cost and Performance Optimization
(Contract No. DE-AC26-99FT40342)

Task 1 Topical Report
IGCC Plant Cost Optimization

Volume 3 of 3
Appendices F through L

May 2002

Work Performed from September 1999 to January 2002

Prepared by:

Bechtel Corporation
3000 Post Oak Boulevard
Houston, TX 77056

Global Energy Inc.
Suite 3800
1000 Louisiana Street
Houston, TX 77002

Nexant Inc.
Suite 4100
44 Montgomery St.
San Francisco, CA 94104

Appendix F - Subtask 1.5

Comparison of Coal and Coke IGCC Plants

Subtask 1.5

Comparison of Coal and Coke IGCC Plants

The objective of Subtask 1.5 is to highlight the differences between single-train coal and coke fueled IGCC power plants located on the U. S. Gulf Coast. Both plant designs were to be developed from the design of the larger, optimized Subtask 1.3 Petroleum Coke IGCC Coproduction Plant which is located adjacent to a petroleum refinery and coproduces hydrogen and steam for the refinery. The two single-train coal and coke power plants are to be compared to the un-optimized Wabash River Greenfield IGCC Plant.

Plant Descriptions and Comparison

Subtask 1.3 generated the optimized plant design which was the starting point for developing the Subtask 1.5 single-train IGCC plants. The Base Case Subtask 1.3 Petroleum Coke IGCC Coproduction Plant is a two-train plant that is designed to process 5,399 TPD of the dry petroleum coke shown in Table 1. It produces 460.7 MW of export electric power and coproduces 80 MMscfd of 1,000 psig hydrogen and 980,000 lb/hr of 700 psig / 750^{o}F steam for sale to an adjacent petroleum refinery. In addition it also produces 372 TPD of sulfur and 194 TPD of slag. Each gasification train contains a spare gasification reactor vessel that can be placed in service whenever it is necessary to replace the refractory in the other vessel. The char is removed from the syngas by a cyclone followed by a wet particulate scrubbing system and is recycled back to the gasification reactor. After the acid gas removal system, some syngas is split off and sent to the hydrogen plant. The remaining syngas from each train feeds one of two General Electric 7FA+e combustion turbines, each of which generates 210 MW of power, followed a high temperature heat recovery (HRSG) system. The high pressure steam generated in both HRSGs and the PSA tail gas boiler is sent to a single steam turbine which generates 150 MW of power. The Base Case Subtask 1.3 Plant has an EPC cost of 764 million mid-year 2000 dollars.[1]

The coal and coke Subtask 1.5 IGCC power plants are single-train plants processing the feedstocks shown in Table 1. Electricity is the principal product (no coproduct hydrogen and export steam are produced). Each train is similar to those of the Base Case Subtask 1.3 plant except where modifications were required to eliminate the hydrogen and steam productions, and to account for the coal processing requirements. Table 2 compares the input and output streams for the Subtask 1.5 plants with the Subtask 1.1 Wabash River Greenfield Plant. Both Subtask 1.5 plants produce more power from less feed, (are more efficient,) and cost less than the un-optimized Subtask 1.1 Wabash River Greenfield Plant. Figures 1 and 2 are detailed block flow diagrams of the Subtask 1.5 single-train coal and coke IGCC power plants, respectively. Figure 3 is a detailed block flow diagram of the Subtask 1.1 Wabash River Greenfield Plant. It is included for reference.

[1] All plant EPC costs mentioned in this report are order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted.

The designs of the coal and coke IGCC power plants are very similar except for the following differences which are a result of either the difference in feedstock properties or a result of the coke plant utilizing some of the refinery facilities.

- The coal plant requires feed handling and storage facilities because the adjacent refinery delivers coke by conveyor directly to the active coke storage pile.
- The coal plant includes river water intake facilities whereas the coke plant uses those of the adjacent refinery.
- The coal plant includes a waste water outfall system whereas the coke plant uses the adjacent refinery's outfall system.
- The post reactor residence vessel has been eliminated in the coke plant.
- The coke plant requires the use of flux and has additional flux receiving, storage and delivery facilities.
- The coal plant produces more slag, and consequently, has larger slag handling facilities.
- The sulfur removal and sulfur recovery facilities are larger for the coke plant because the coke has a higher sulfur content than the coal.
- The water discharge rate from the syngas scrubbing column is larger for the coal plant because the coal has a higher chloride content than the coke.
- In the coal plant, the gasification area requires more intermediate pressure steam than it produces, and consequently, some is withdrawn from the combined cycle section and sent to the gasification area. However, the gasification area of the coke plant produces excess intermediate pressure steam which it sends it to the combined cycle section for power production.

Figures 4 and 5 are basic site plans of the Subtask 1.5 single-train coke and coal IGCC power plants, respectively. There are slight differences between the site plans because the coke is delivered to the plant site directly from the adjacent refinery by conveyor, and therefore, a large amount of on-site coke storage is not required. These site plans were generated using a plant layout computer model with the objective of developing a compact plant layout which minimized the amount of large bore pipe and still allows for ease of construction and maintenance.

The Case 1.5A coal plant process more coal than the coke plant because the coal contains less energy per pound and has more ash (inert material) than the coke. Consequently, it produces significantly more slag. Since the coal contains less than half as much sulfur as the coke, the coal plant produces less than half as much sulfur as the coke plant. Table 3 shows that both plants effectively remove almost all of the sulfur in the feed. The coal plant removes about 98.5% of the sulfur, and the coke plant removes about 99.4%. Both sulfur removal rates are greater than the 96.8% removal rate of the Subtask 1.1 Wabash River Greenfield Plant. On a percentage basis, the sulfur removal from the coke plant is greater than that from the coke plant for two reasons. First, there is more sulfur to remove, and secondly, more sulfur is sent to the incinerator from the coal plant because the higher ash content generates more vent gas going to the incinerator. The NOx and CO emissions from both Subtask 1.5 plants are lower than those of the Subtask 1.1 Wabash River Greenfield Plant because of an improved process design and use of a more advanced gas turbine.

Both the Subtask 1.5 coal and coke plants are more efficient than the un-optimized Subtask 1.1 Wabash River Greenfield Plant. On an HHV basis, the coal plant is about 0.8% more efficient, and the coke plant is about 2.3% more efficient.

Table 4 contains a more detailed comparison of the Subtask 1.5 coal and coke IGCC power plants by plant section. The Case 1.5A coal plant has a higher makeup water rate and a higher process water discharge rate than the Case 1.5B coke plant in order to remove the larger amount of chlorides that are present in the coal.

Cost Estimates

Table 2 compares the order of magnitude EPC cost estimates for the Subtask 1.5 coal and coke plants with the Subtask 1.1 Wabash River Greenfield plant. The installed cost of the Case 1.5A coal plant is about 375 million mid-year 2000 dollars, about 17% less than the Subtask 1.1 plant. The installed cost of the Case 1.5B coke plant is about 367 million mid-year 2000 dollars, about 19% less than the Subtask 1.1 plant. Because the Subtask 1.5 plants use a larger gas turbine and are more efficient than the Subtask 1.1 plant, on a dollar per unit of power basis ($/kW-hr) the cost reductions are greater, almost 22% for the coal plant. For the coke plant, the cost reduction is about 25.1%. As is the case in the Subtask 1.2 and 1.3 plant cost comparison, the majority of the savings are in the gasification area of the plant.

These costs savings resulted from the application of the VIP (Value Improving Practices) and Optimization items shown in Table 5 used in developing the designs for the Subtask 1.3 Petroleum Coke IGCC Coproduction Plant. Therefore, these items are included in the subsequent Subtask 1.5 coal and coke IGCC power plants.

Table 6 contains an equipment list by process area for the coal and coke IGCC power plants. With specific exceptions in the areas of feed handling, water treatment, waste water outfall, and gasification, the equipment lists for the coal and coke plants are nearly identical. Therefore, construction and operation of petroleum coke IGCC plants should help to build an experience base for either fuel and assist with the future market penetration of coal fueled IGCC power plants.

Availability Analysis

Plant availability is required to calculate the expected annual production rates from the design production rates. An availability analysis similar to that done for Subtask 1.3 based on current Wabash River Repowering project availability data was performed for the Subtask 1.5 cases.[2] Table 7 shows the design and expected daily average feed and product rates for the Subtask 1.5A and 1.5B coal and coke cases both with and without the use of backup natural gas and compares them with those of the Subtask 1.1 Wabash River Repowering Project. Without the use of backup natural gas, the Subtask 1.5 plant has a power availability of 78.2%. This means that the average daily production rate will be 78.2% of the design rate. This is almost 3% better than the 75.5% availability of the Subtask 1.1 Wabash River Repowering Project. With backup natural gas, the Subtask 1.5 coal and coke power availabilities increase to about 92.9% and 92.5% of their respective design rates. Wabash River availability should further improve as the plant continues to operate and make improvements.

[2] "Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

Financial Analysis

The DCF (discounted cash flow) financial model that was developed by Bechtel Technology and Consulting (now Nexant, Inc,) for the DOE was used to perform a financial analysis for these single-train coal and coke IGCC power plants.[3] For each of the two Subtask 1.5 cases, two sub-cases were considered. In the first sub-case, overall plant availability is limited by the availability of syngas. In the second sub-case, natural gas (at 2.60 $/MMBtu) is used as a backup fuel during periods when syngas is not available. Only the first sub-case (i.e.; no natural gas backup fuel) was considered for the Subtask 1.1 Wabash River Greenfield Plant.

The basic financial assumptions utilized herein are the same as those that were used for the Subtask 1.3 financial analysis. However, the project schedule from award to commercial operations was shortened by 2 months to 40 months. The length of the schedule is limited by the current backlog and time required to obtain combustion and/or steam turbines.

In addition, two basic financing scenarios are considered. In the first scenario, the loan interest rate is 10% with a 3% up-front financing fee. The 3% financing fee may be considered as equivalent to points on a home mortgage. In the second scenario, which is more representative of current economic conditions, the loan interest rate has been reduced to 8% with the same 3% financing fee.

Figure 6 shows the return on investment as a function of the power selling price for the four Subtask 1.5 and Subtask 1.1 cases with a 10% loan interest rate. As expected, the two cases which use natural gas as backup fuel have higher returns on investment than their corresponding cases which do not use backup fuel. At a given power selling price, the coke plant has a return on investment than that of the corresponding coal case. This is because of the following three reasons.

1. The coal cost of 22 $/ton is significantly more than the 0 $/ton cost of the coke. The cost of the small amount of flux at 5 $/ton that is required to be added with the coke is much less than the cost of the coal.
2. The coke plant costs less than the coal plant, 367 MM$ vs. 375 MM$.
3. The coke plant produces more export power than the coal plant, 291.3 vs. 284.6 MW.

At a given power selling price, all of the Subtask 1.5 cases have a significantly higher return on investment than the Subtask 1.1 Wabash River Greenfield Plant.

Figure 7 shows the return on investment as a function of the power selling price for the five cases with a 8% loan interest rate. The results are similar to those in the previous figure with a 10% loan interest rate, but the return on investment is about 4% higher.

Table 8 shows the required power selling price for a 12% return on investment for all the cases at both the 8 and 10% loan interest rates. With a 8% loan interest rate, the Case 1.5A coal plant requires a power selling price of 45.9 to 50.4 $/MW-hr to obtain a 12% return on investment. The lower value corresponding to situation where natural gas backup is used to produce power when syngas is unavailable. The Case 1.5B coke plant requires a power selling price of 37.8 to 40.6 $/MW-hr to obtain a 12% return on investment. Again, the lower value corresponds to the situation where natural gas backup is used to produce power when syngas is unavailable. At a 10% loan interest rate, the required power selling prices are from 2.8 to 3.5 $/MW-hr higher. All these required power selling prices are significantly lower than the 62.9 and 67.5 $/MW-hr power

[3] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital BudgetingEvaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

selling price required for the Subtask 1.1 Wabash River Greenfield Plant to generate a 12% return on investment without natural gas backup. These Subtask 1.5 power prices compare favorably with the 2001 EIA forecast of 48 $/MW-hr with -0.6% escalation for industrial power and 80 $/MW-hr with a -0.8% escalation for commercial power.[4]

The required power selling price to produce a 12% return on investment for the Base Case Subtask 1.3 Petroleum Coke IGCC Coproduction Plant was 31.7 to 34.7 $/MW-hr depending upon what coproduct prices are used. This coproduction plant has lower required product selling prices for the following reasons.

1. It produces more valuable products, namely hydrogen and steam which are sold to the adjacent refinery, rather than just the lower value electric power.
2. It is a larger two-train plant that can take advantage of the economy of scale in the coke receiving and storage area, steam turbine, and balance of plant facilities.

Multiple train IGCC plants with or without coproduction should have lower costs of electricity than the Subtask 1.5 plants.

Furthermore, switching to an advanced dry particulate removal system could improve the return on investment by about 1.5% or reduce the required power selling price by about 1 to 1.5 $/MW-hr for either coal or coke IGCC power plants. Also for the coal plant, additional optimization of the syngas scrubbing system necessitating upgrading the metallurgy may further increase the design output by about 3 to 5 MW; thereby reducing both the heat rate and the $/MW-hr power cost, making it closer to that of the coke plant.

It appears that the first domestic commercial applications for petroleum coke gasification will be for plants that are associated with petroleum refineries and/or chemical facilities where they can coproduce hydrogen and steam in addition to electric power. Experience gained in the design and operation of either of these plants will lead to additional cost reductions which will make the single train coal and coke IGCC power plants more competitive with current base-load power plants, especially with the current high natural gas prices.

[4] Energy Information Administration, "Annual Energy Outlook 2001 with Projections to 2020," U.S. Department of Energy, Washington, DC, December 2000,

Table 1

Feedstocks for the Coal and Petroleum Coke IGCC Power Plants

	Case 1.5A		**Case 1.5B**	
Type	**Coal**		**Petroleum Coke**	
Feedstock	Illinois No. 6		Green Delayed Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	14,132
LHV, Btu/lb	12,275	10,495	14,548	13,846
Analysis, wt %				
Carbon	70.02	59.87	87.86	83.62
Hydrogen	4.99	4.27	3.17	3.02
Nitrogen	1.30	1.11	0.89	.85
Sulfur	2.58	2.21	6.93	6.60
Oxygen	8.27	7.07	1.00	0.95
Chlorine	0.13	0.11	0.01	0.01
V & Ni	Nil	Nil	1900 ppm	1812 ppm
Ash	12.70	10.86	0.14	0.13
Moisture	NA	14.50	NA	4.83
Total	100	100	100	100

Table 2

Input and Output Streams for the Coal and Petroleum Coke IGCC Power Plants

Case	Case 1.5A	Case 1.5B	Subtask 1.1
Description	Optimized Design	Optimized Design	Wabash River Greenfield Plant
Feedstock	Illinois No 6 Coal	Petroleum Coke	Illinois No. 6 Coal
Feeds			
Coal/Coke Feed Rate, TPD dry	2,335	1,977	2,259
Flux Feed Rate, TPD	0	40	0
Oxygen Flow (Contained O_2), TPD	1,900	2,021	2,026
Products			
Net Power Output, MW	284.6	291.3	269.3
Slag, TPD	364	71	356
Sulfur, TPD	60	136	57
Heat Rate, Btu/kW-hr			
HHV	8,717	8,397	8,912
LHV	8,393	8,227	8,580
Efficiency, % HHV	39.14	40.64	38.29
Total Installed Plant Cost*, MM$	375	367	452.6
Total Installed Plant Cost, $/kW	1,318	1,261	1,684

* This order of magnitude plant cost estimate excludes contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted.

Table 3

Environmental Emissions Summary of the Coal and Petroleum Coke IGCC Power Plants*

Case	Case 1.5A	Case 1.5B	Subtask 1.1
Description	Optimized Design	Optimized Design	Wabash River Greenfield Plant
Feedstock	Illinois No 6 Coal	Petroleum Coke	Illinois No. 6 Coal
Total Gas Turbine Emissions			
GT/HRSG Stack Flow Rate, lb/hr	3,983,500	3,983,500	3,770,200
GT/HRSG Stack Exhaust Temperature, ^oF	222	204	238
Emissions (at 15% oxygen, dry)			
SOx, ppmvd	3	3	3
SOx, as SO_2, lb/hr	24	24	23
NOx, ppmvd	10	10	25
NOx as NO_2, lb/hr	69	68	160
CO, ppmvd	10	10	15
CO, lb/hr	40	40	55
Incinerator Emissions			
Stack Flow Rate, lb/hr	21,870	21,990	22,120
Stack Exhaust Temperature, ^oF	500	500	500
Emissions (at 3% oxygen, dry)			
SOx, ppmvd	2,473	1,996	6,662
SOx, as SO_2, lb/hr	118	95	290
NOx, ppmvd	40	40	40
NOx as NO_2, lb/hr	1	1	1
CO, ppmvd	50	50	50
CO, lb/hr	1	1	1
Total Plant Emissions			
Exhaust Flow Rate, lb/hr	4,005,300	4,005,500	3,792,300
Emissions			
SOx, ppmvd	19	16	42
SOx, as SO_2, lb/hr	142	119	312
NOx, ppmvd	13	13	30
NOx as NO_2, lb/hr	69	69	161
CO, ppmvd	13	12	17
CO, lb/hr	41	41	56
VOC and Particulates, lb/hr	NIL	NIL	NIL
Opacity	0	0	0
Sulfur Removal, %	98.6	99.5	96.8

* Expected emissions performance

Table 4

Comparison of the Coal and Petroleum Coke IGCC Power Plants by Plant Section

Case Description Feedstock	**Case 1.5A** Optimized Design Illinois No. 6 Coal	**Case 1.5B** Optimized Design Petroleum Coke	**Subtask 1.1** Wabash River Greenfield Plant Illinois No. 6 Coal	**Comments** The two optimized plants (Cases 1.5A and 1.5B) are located on the U. S. Gulf Coast. The Wabash River Greenfield Plant (Case 1.1) is located in the Midwest.
100/150 Solid Feed Preparation				Petroleum coke requires flux addition.
Rate, TPD dry	2,335	1,977	2,259	
Flux, TPD	0	40	0	
200 Air Separation Unit				Single train plant
Oxygen Rate (95% O_2), TPD	2,015	2,143	2,149	
Oxygen Rate (as O_2), TPD	1,900	2,021	2,026	
300 Gasification				
High Pressure Steam Production, lb/hr	420,600	454,500	470,700	
350 Slag Handling and Storage				The Illinois No. 6 coal contains 12.7% ash (dry basis) vs. 0.14% for the coke.
Slag Rate, TPD (15% water)	364	71	356	
400 Syngas Cooling				
Clean Syngas Rate, lb/hr	446,952	426,663	411,421	
Gas HHV, MMBtu/hr	1,929	1,893	1,798	
Gas LHV, MMBtu/hr	1,796	1,796	1,676	
Composition, mole % dry basis				
H_2	33.2	27.2	33.2	
CO	46.3	59.6	46.8	
CO_2	14.3	9.0	14.8	
CH_4	3.6	1.6	2.4	
Other	2.6	2.6	2.8	
420 Sulfur Recovery				The Illinois No. 6 coal contains 2.58% sulfur (dry basis) vs. 6.93% for the coke.
Sulfur Production, TPD	60	136	57	
Sulfur Removal, %	98.5	99.4	96.7	

Table 4 (Continued)

Comparison of the Coal and Petroleum Coke IGCC Power Plants by Plant Section

Case Description	**Case 1.5A** Optimized Design	**Case 1.5B** Optimized Design	**Subtask 1.1** Wabash River Greenfield Plant	**Comments**
500 Gas Turbine				Case 1.1 uses an older GE 7FA gas turbine that is smaller than the newer GE 7FA+e gas turbine which is used in Cases 1.5A and 1.5B. Thus, there is some economy of scale The GE 7FA+e has lower emissions than the older GE 7FA.
Energy Input, MM Btu/hr LHV	1,796	1,796	1,676	
GT Power, MW	210	210	192	
Emissions,				
SOx, ppmvd	3	3	3	
NOx, ppmvd(at 15% oxygen, dry)	10	10	25	
CO, ppmvd	10	10	15	
600 Steam Turbine				Subtask 1.5 uses a 1450 psig/1050°F/ 1050°F steam cycle and Subtask 1.1 uses a 1450 psig/1000°F/1000°F steam cycle.
Power, MW	113.0	121.3	118	
900 Balance of Plant				
Total Internal Power Use, MW	38.4	40.0	40.7	
Process Water Streams, gpm				The total water discharge rate includes a 150 gpm allowance for storm water.
Total Inlet	2,840	2,525	2,281	
Cooling Tower Blowdown	275	255	329	
Total Water Discharge	898	657	756	
Total Plant				
Net Heat Rate, HHV Btu/kW-hr	8,717	8,397	8,912	
Efficiency, % HHV	39.14	40.64	38.29	
Total Installed Cost*, MM$	375	367	452.6	
Total Installed Cost, $/kW (net)	1,318	1,261	1,684	

* This order of magnitude plant cost estimate excludes contingency, taxes, licensing fees and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted.

Table 5

VIP and Optimization Items

Plant Section	Description	Included in Case Coal 1.5A	Included in Case Coke 1.5B
100	Simplified solids handling system	No	Yes
150	Removed feed heaters and spare pumps	Yes	Yes
300	• Maximum use of slurry quench in second stage gasifier	Yes	Yes
	• Maximum syngas moisturization	Yes	Yes
	• Use of a cyclone and wet particulate removal system rather than dry char filters to clean the syngas (no hot candle filters)	Yes	Yes
	• Removed T-120 post reactor residence vessel	No	Yes
400/420	Simplified Claus plant, amine and sour water stripper resulting in lower incinerator emissions	Yes	Yes
500	Use of a state-of-the-art GE 7FA+e gas turbine with 210 MW output and lower NOx	Yes	Yes
	Use of least cost diluent (steam) in the gas turbine	Yes	Yes
General	• Bechtel's Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach	Yes	Yes
	• Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs	Yes	Yes
	• Availability analysis was used to select design with maximum on-stream time	Yes	Yes
	• The COMET plant layout model was used to develop a compact plant layout and minimize the amount of large bore piping.	Yes	Yes
	• Design features were added to reduce annual O&M costs	Yes	Yes

Table 6

Equipment List for the Coal and Coke IGCC Power Plants

Fuel Handling – 100	***COAL***	***COKE****
Unit Train Rail Loop	X	
Rotary Coal Car Dumper	X	
Rotary Car Dumper Coal Pit	X	
Rotary Dumper Vibratory Feeders	X	
Rotary Dumper Building & Coal Handling Control Control/Electrical Rooms	X	
Rotary Car Dumper Dust Collector	X	
Rotary Car Dumper Sump Pumps	X	
Coal Car Unloading Conveyor	X	
Coal Crusher	X	
Reclaim Coal Grizzly	X	
Coke Storage Dome		X
Reclaim Conveyors	X	X
Storage/Feed Bins	X	X
Reclaim Pit Sump Pumps	X	
Coal Dust Suppression System	X	
Coal/Coke Handling Electrical Equipment and Distribution	X	X
Electric Hoist	X	X
Metal Detector	X	X
Magnetic Separator	X	X
Flux Silo		X
Vibrating Feeder		X
Slurry Preparation – 150	***COAL***	***COKE***
Weigh Belt Feeder	X	X
Rod Charger	X	X
Rod Mill	X	X
Rod Mill Product Tank	X	X
Rod Mill Product Tank Agitator	X	X
Rod Mill Product Pumps	X	X
Recycle Water Storage Tank	X	X
Recycle Water Pumps	X	X
Slurry Storage Tank	X	X
Slurry Storage Tank Agitator	X	X
Slurry Recirculation Pumps	X	X
Solids Recycle Tank	X	X
Solids Recycle Tank Agitator	X	X
Solids Recycle Pumps	X	X
Rod Mill Lube Oil Pumps	X	X
Slurry Feed Pumps (1^{st} Stage)	X	X
Slurry Feed Pumps (2^{nd} Stage)	X	X

Table 6 (Continued)

Equipment List for the Coal and Coke IGCC Power Plants

ASU – 200	***COAL***	***COKE***
Air Separation Unit including:	X	X
Main Air Compressor		
Air Scrubber		
Oxygen Compressor		
Cold Box (Main Exchanger)		
Oxygen Compressor Expander		
Liquid Nitrogen Storage		
ASU & Gasifier Area Cooling Water - 250	***COAL***	***COKE***
Cooling Water Circulation Pump	X	X
Cooling Tower (S/C)	X	X
Gasification - 300	***COAL***	***COKE***
Main Slurry Mixers	X	X
Second Stage Mixer	X	X
Gasifier	X	X
Post Reactor Residence Vessel	X	
High Temperature Heat Recovery Unit	X	X
Cyclone Separators	X	X
Slag Pre-Crushers	X	X
Slag Crushers	X	X
Reactor Nozzle Cooling Pumps	X	X
Crusher Seal Water Pumps	X	X
Syngas Desuperheater	X	X
Nitrogen Heater	X	X
Pressure Reduction Units	X	X
Syngas Venturi Scrubber	X	X
Syngas Scrubber Column	X	*X*
Syngas Scrubber Roughing Filter	X	*X*
Syngas Scrubber Final Filter	X	*X*
Syngas Scrubber Recycle Pumps	X	*X*
Slag Handling – 350	***COAL***	***COKE***
Slag Dewatering Bins	X	X
Slag Gravity Settler	X	X
Slag Water Tank	X	X
Slag Water Pumps	X	X
Gravity Settler Bottoms Pumps	X	X
Slag Recycle Water Tank	X	X
Slag Feedwater Quench Pumps	X	X
Slag Water Recirculation Pumps	X	X
Polymer Pumps	X	X
Slag Recycle Water Cooler	X	X

Table 6 (Continued)

Equipment List for the Coal and Coke IGCC Power Plants

LTHR/AGR – 400	*COAL*	*COKE*
Syngas Recycle Compressor	X	X
Syngas Recycle Compressor K. O. Drum	X	X
Syngas Heater	X	X
COS Hydrolysis Unit	X	X
Amine Reboiler	X	X
Sour Water Condenser	X	X
Sour Gas Condensate Condenser	X	X
Sour Gas CTW Condenser	X	X
Sour Water Level Control Drum	X	X
Sour Water Receiver	X	X
Sour Gas K.O. Drum	X	X
Sour Water Carbon Filter	X	X
MDEA Storage Tank	X	X
Lean Amine Pumps	X	X
Acid Gas Absorber	X	X
MDEA Cross-Exchangers	X	X
MDEA CTW Coolers	X	X
MDEA Carbon Bed	X	X
MDEA Post-Filter	X	X
Acid Gas Stripper	X	X
Acid Gas Stripper Recirculation Cooler	X	X
Acid Gas Stripper Reflux Drum	X	X
Acid Gas Stripper Quench Pumps	X	X
Acid Gas Stripper Reboiler	X	X
Acid Gas Stripper Overhead Filter	X	X
Lean MDEA Transfer Pumps	X	X
Acid Gas Stripper K.O. Drum	X	X
Acid Gas Stripper Preheater	X	X
Amine Reclaim Unit	X	X
Condensate Degassing Column	X	X
Degassing Column Bottoms Cooler	X	X
Sour Water Transfer Pumps	X	X
Ammonia Stripper	X	X
Ammonia Stripper Bottoms Cooler	X	X
Stripped Water Transfer Pumps	X	X
Quench Column	X	X
Quench Column Bottoms Cooler	X	X
Stripped Water Transfer Pumps	X	X
Degassing Column Reboiler	X	X
Ammonia Stripper Reboiler	X	X
Syngas Heater	X	X
Syngas Moisturizer	X	X
Moisturizer Recirculation Pumps	X	X

Table 6 (Continued)

Equipment List for the Coal and Coke IGCC Power Plants

Sulfur Recovery – 420	***COAL***	***COKE***
Reaction Furnace/Waste Heat Boiler	X	X
Condensate Flash Drum	X	X
Sulfur Storage Tank	X	X
Storage Tank Heaters	X	X
Sulfur Pump	X	X
Claus First Stage Reactor	X	X
Claus First Stage Heater	X	X
Claus First Stage Condenser	X	X
Claus Second Stage Reactor	X	X
Claus Second Stage Heater	X	X
Claus Second Stage Condenser	X	X
Condensate Level Drum	X	X
Hydrogenation Gas Heater	X	X
Hydrogenation Reactor	X	X
Quench Column	X	X
Quench Column Pumps	X	X
Quench Column Cooler	X	X
Quench Strainer	X	X
Quench Filter	X	X
Tail Gas Recycle Compressor	X	X
Tail Gas Recycle Compressor Intercooler	X	X
Tank Vent Blower	X	X
Tank Vent Combustion Air Blower	X	X
Tank Vent Incinerator/Waste Heat Boiler	X	X
Tank Vent Incinerator Stack	X	X
GT / HRSG – 500	***COAL***	***COKE***
Gas Turbine Generator (GTG), GE 7FA+e Dual Fuel (Gas and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.	X	X
GTG Erection (S/C)	X	X
Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, with Integral Deaerator	X	X
HRSG Stack (S/C)	X	X
HRSG Continuous Emissions Monitoring Equip.	X	X
HRSG Feedwater Pumps	X	X
HRSG Blowdown Flash Tank	X	X
HRSG Atmospheric Flash Tank	X	X
HRSG Oxygen Scavenger Chemical Injection Skid	X	X
HRSG pH Control Chemical Injection Skid	X	X
GTG Iso-phase Bus Duct	X	X
GTG Synch Breaker	X	X
Power Block Auxiliary Power XformerS	X	X

Table 6 (Continued)

Equipment List for the Coal and Coke IGCC Power Plants

Stg. & Aux. - 600	***COAL***	***COKE***
Steam Turbine Generator (STG), Reheat, TC2F, Complete with Lube Oil Console	X	X
Steam Surface Condenser, 316L tubes	X	X
Condensate (hotwell) pumps	X	X
Circulating Water Pumps	X	X
Auxiliary Cooling Water Pumps	X	X
Cooling Tower	X	X
Balance Of Plant - 900	***COAL***	***COKE****
High Voltage Electrical Switch Yard (S/C)	X	X
Common Onsite Electrical and I/C Distribution	X	X
DCS	X	X
In-Plant Communication System	X	X
15KV, 5KV and 600V Switchgear	X	X
BOP Electrical Devices	X	X
Power Transformers	X	X
Motor Control Centers	X	X
River Water - Makeup Water Intake and Plant Supply Pipeline	X	
<u>Water Intake System S/C Including;</u>	X	
Intake Structure	X	
Pumphouse	X	
Makeup Pumps	X	X
Substation & MCC	X	X
Lighting, Heating & Ventilation	X	X
Makeup Water Treatment Storage and Distribution	X	X
Water Treatment Building Equipment	X	X
Hydroclone Clarifier	X	
Coagulation Storage Silo	X	
Clarifier Lime Storage Silo	X	
Gravity Filter	X	
Clear Well	X	
Clear Well Water Pumps	X	
Water Softner Skids	X	
Carbon Filters	X	X
Cation Demineralizer Skids	X	X
Degasifiers	X	X
Anion Demineralizer Skids	X	X
Demineralizer Polishing Bed Skids	X	X
Bulk Acid Tank	X	X
Acid Transfer Pumps	X	X
Demineralizer - Acid Day Tank Skid	X	X
Bulk Caustic Tank Skid	X	X
Caustic Transfer Pumps	X	X

Table 6 (Continued)

Equipment List for the Coal and Coke IGCC Power Plants

Balance of Plant – 900 (Continued)	***COAL***	***COKE***
Demineralizer - Caustic Day Tank Skid	X	X
Firewater Pump Skids	X	X
Waste Water Collection and Treatment	X	X
Oily Waste - API Separator	X	X
Oily Waste - Dissolved Air Flotation	X	X
Oily Waste Storage Tank	X	X
Sanitary Sewage Treatment Plant	X	X
Wastewater Storage Tanks	X	X
Reverse Osmosis Unit for Chloride Removal	X	X
Waste Water Outfall	X	
Monitoring Equipment	X	X
Common Mechanical Systems	X	X
Shop Fabricated Tanks	X	X
Miscellaneous Horizontal Pumps	X	X
Auxiliary Boiler	X	X
Safety Shower System	X	X
Flare	X	X
Flare K.O. Drum	X	X
Flare K.O. Drum Pumps	X	X
Chemical Feed Pumps	X	X
Chemical Storage Tanks	X	X
Chemical Storage Equipment	X	X
Laboratory Equipment	X	X

* The petroleum coke IGCC plant is assumed to be located adjacent to a petroleum refinery, and thus, can share some infrastructure with the refinery. It is assumed that

1. The refinery delivers the coke to the coke storage dome.
2. The IGCC plant gets the river water from the refinery water intake system.
3. The refinery processes the waste water from the IGCC plant through the refinery waste water treatment facilities.

Table 7

Design and Daily Average Feed and Product Rates for the Coal and Coke IGCC Plants

	Case 1.5A - Coal			Case 1.5B - Coke			Subtask 1.1 - Coal	
		Daily Average			Daily Average			Daily Average
	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas
Feeds								
Coal, TPD dry	2,335	1,826	1,826				2,259	1,705
Coke, TPD dry				1,977	1,546	1,546		
Flux, TPD				40	31.3	31.3		
Natural Gas, MMscfd	0	0	6,929	0	0	6,929	0	0
Products								
Power, MW	284.6	222.5	264.4	291.3	227.8	269.4	269.3	203.2
Sulfur, TPD	60	46.9	46.9	136	106	106	57	43
Slag, TPD	364	285	285	71	55.5	55.5	356	281

Table 8

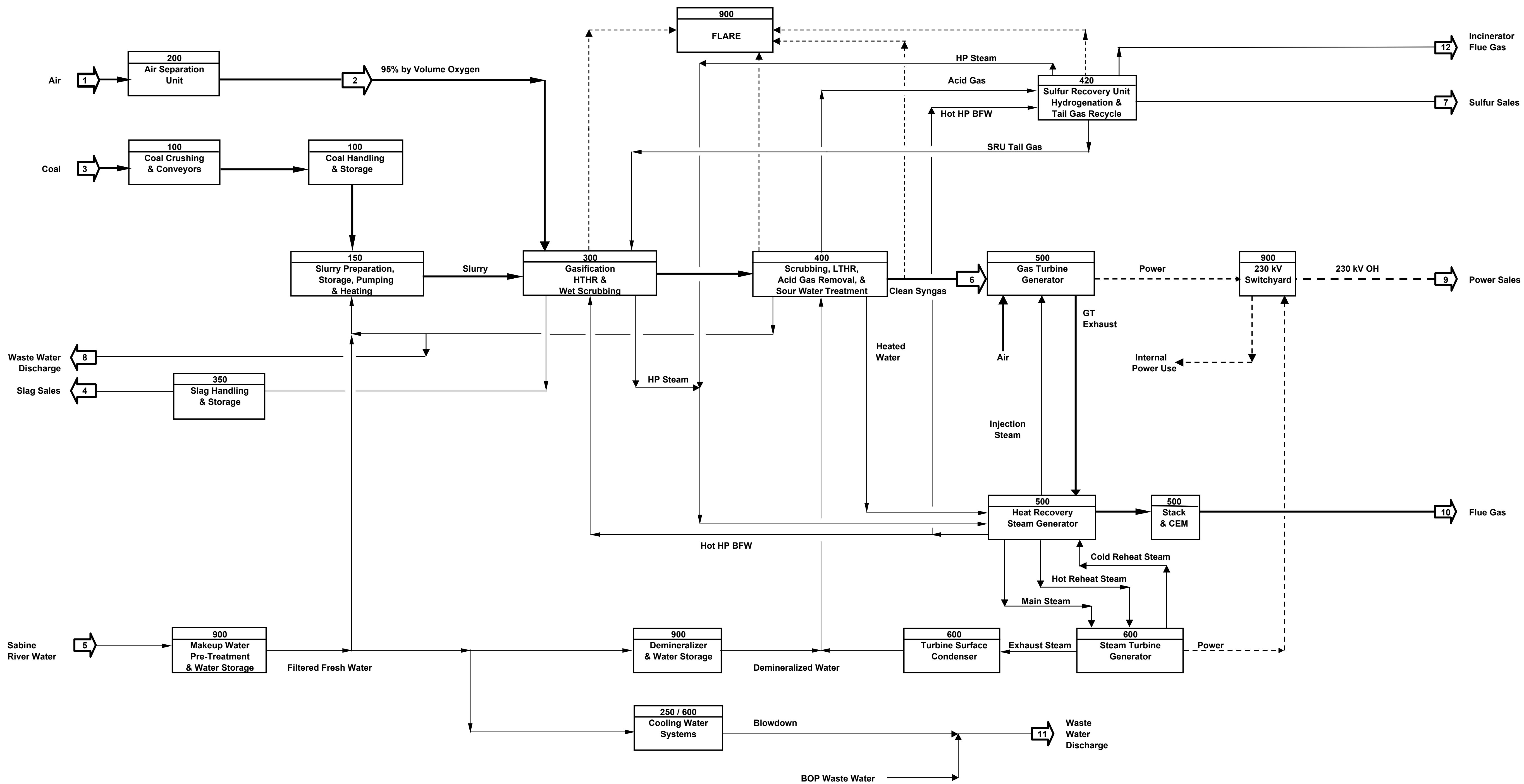
Required Power Selling Price for a 12% Return on Investment

	Required Power Selling Price, $/MW-hr				
Loan Interest Rate	Case 1.5A Coal w/o Natural Gas Backup	Case 1.5A Coal with Natural Gas Backup	Case 1.5B Coke w/o Natural Gas Backup	Case 1.5B Coke with Natural Gas Backup	Subtask 1.1 Coal w/o Natural Gas Backup
10%	53.9	48.9	43.9	40.6	67.5
8%	50.4	45.9	40.6	37.8	62.9

Figure 1

Detailed Block Flow Diagram of the

Case 1.5A Single-Train Coal IGCC Power Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 8,786 Tons/Day	Oxygen 2,015 Tons/Day	Coal 2,335 Tons/Day	Slag 364 Tons/Day	Water 1,420,000 Lb/Hr	Syngas 446,952 Lb/Hr	Sulfur 60 Tons/Day	Water 36,110 Lb/Hr	Power 284,600 kWe	Flue Gas 3,983,500 Lb/Hr	Water 413,000 Lb/Hr	Flue Gas 21,872 Lb/Hr									
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	NA	NA	Atmos.	Atmos.	Atmos.									
Temperature - F	59	240	NA	NA	70	530	NA	80	NA	222	NA	500									
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,316	NA	NA	NA	NA	NA	NA									
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,019	NA	NA	NA	NA	NA	NA									
Energy - MM HHV/Hr	NA	NA	2,481	NA	NA	1,929	NA	NA	NA	NA	NA	NA									
Energy - MM LHV/Hr	NA	NA	2,389	NA	NA	1,796	NA	NA	NA	NA	NA	NA									
Notes	Dry Basis	1,900 O2	Dry Basis	15%Wtr.	2,840 GPM	to GT	Sales	72 GPM	230 kV		826 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure 1

Subtask 1.5 Case 1.5A

SINGLE TRAIN COAL IGCC POWER PLANT

BLOCK FLOW DIAGRAM

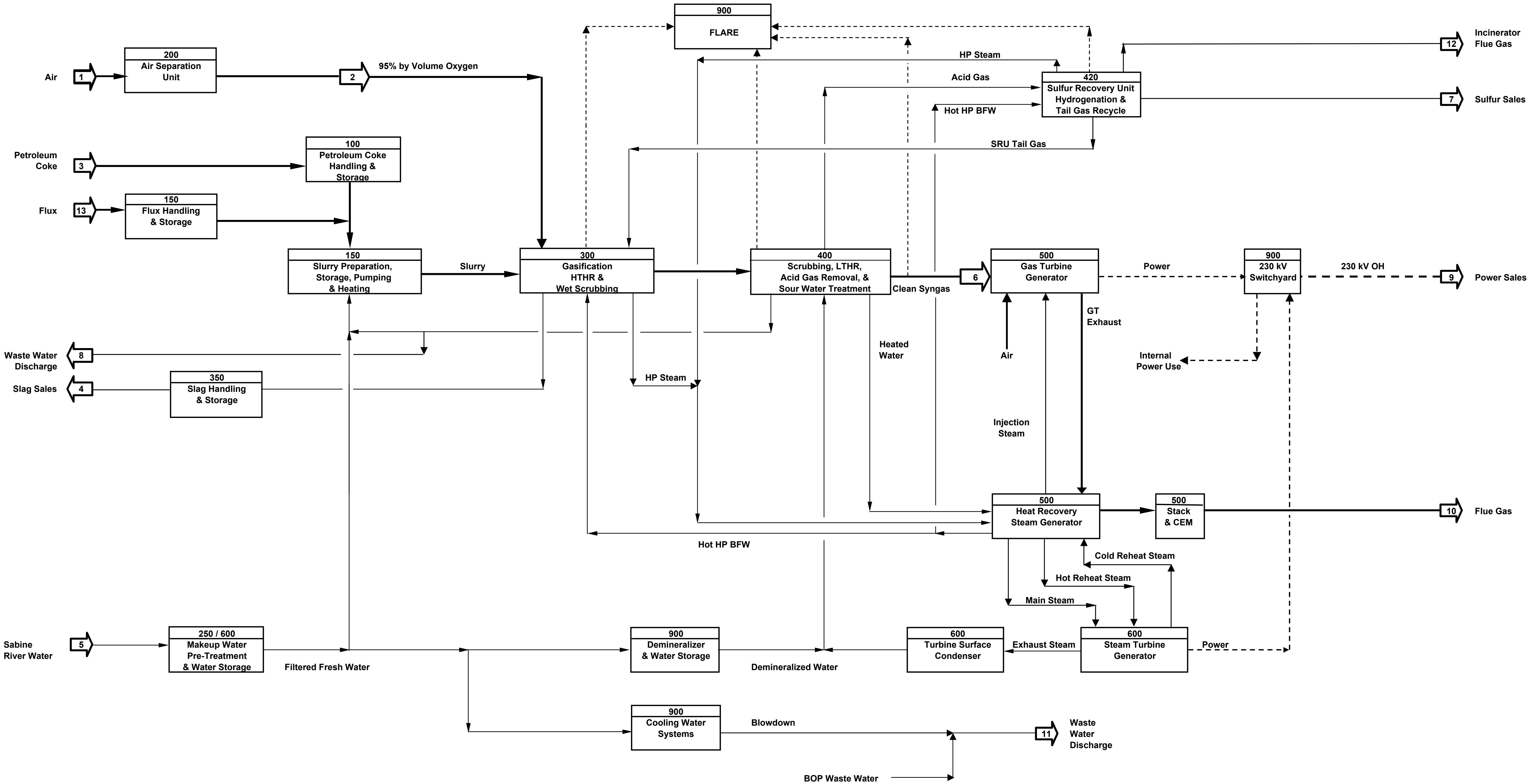
File: Fig 1 1.5A R1.xls

February 21, 2002

Figure 2

Detailed Block Flow Diagram of the

Case 1.5B Single-Train Coke IGCC Power Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 9,344 Tons/Day	Oxygen 2,143 Tons/Day	Coke 1,977 Tons/Day	Slag 71.2 Tons/Day	Water 1,262,500 Lb/Hr	Syngas 426,663 Lb/Hr	Sulfur 136 Tons/Day	Water 794 Lb/Hr	Power 291,300 kWe	Flue Gas 3,983,400 Lb/Hr	Water 332,500 Lb/Hr	Flue Gas 21,989 Lb/Hr	Flux 3,362 Lb/Hr								
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	NA	NA	Atmos.	Atmos.	Atmos.	NA								
Temperature - F	59	240	NA	NA	70	530	NA	80	NA	204	NA	500	NA								
HHV Btu/Lb	NA	NA	14,848	NA	NA	4,437	NA	NA	NA	NA	NA	NA	NA								
LHV Btu/Lb	NA	NA	14,548	NA	NA	4,210	NA	NA	NA	NA	NA	NA	NA								
Energy - MM HHV/Hr	NA	NA	2,446	NA	NA	1,893	NA	NA	NA	NA	NA	NA	NA								
Energy - MM LHV/Hr	NA	NA	2,397	NA	NA	1,796	NA	NA	NA	NA	NA	NA	NA								
Notes	Dry Basis	2021 O2	Dry Basis	15%Wtr.	2,525 GPM	to GT	Sales	2 GPM	230 kV		665 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure 2

Subtask 1.5 Case 1.5B

SINGLE TRAIN PETROLEUM COKE IGCC POWER PLANT

BLOCK FLOW DIAGRAM

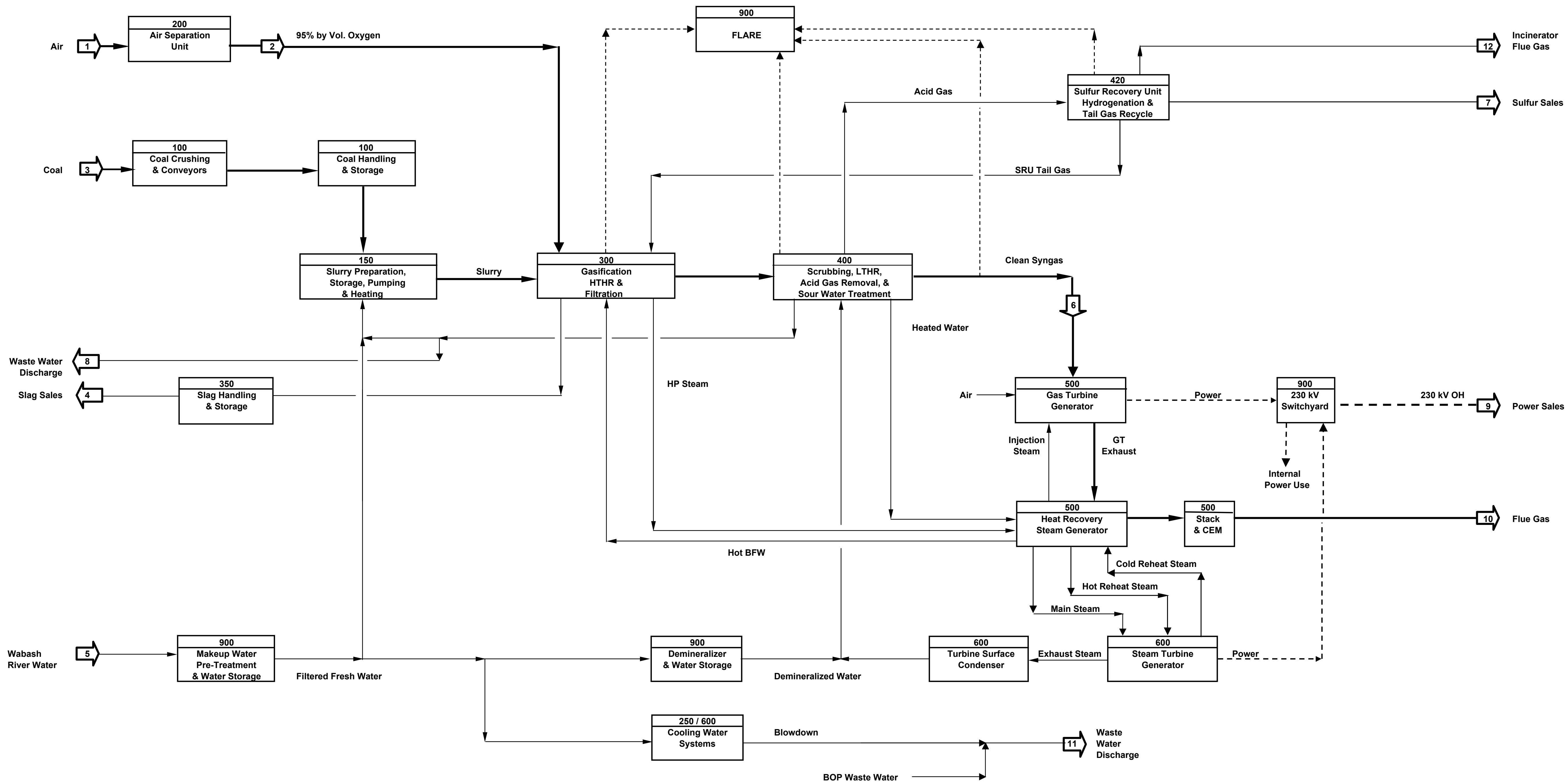
File: Fig 2 1.5B R1.xls

February 21, 2002

Figure 3

Detailed Block Flow Diagram of the

Subtask 1.1 Wabash River Greenfield Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coal	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	Water	Flue Gas									
Flow	9,692	2,130	2,259	356	1,140,500	411,421	57	60,058	269,300	3,770,000	318,000	52,781									
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Lb/Hr	Lb/Hr									
Nominal Pressure - psig	Atmos.	540	NA	NA	50	320	NA	62	NA	Atmos.	Atmos.	Atmos.									
Temperature - F	59	240	NA	NA	70	530	NA	105	NA	238	NA	500									
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,370	NA	NA	NA	NA	NA	NA									
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,074	NA	NA	NA	NA	NA	NA									
Energy - MM HHV/Hr	NA	NA	2,400	NA	NA	1,798	NA	NA	NA	NA	NA	NA									
Energy - MM LHV/Hr	NA	NA	2,311	NA	NA	1,676	NA	NA	NA	NA	NA	NA									
Notes	Dry Basis		Dry Basis	15%Wtr.	2,281 GPM	to GT	Sales	120 GPM	230 kV		636 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure 3

Subtask 1.1

WABASH RIVER GREENFIELD PLANT

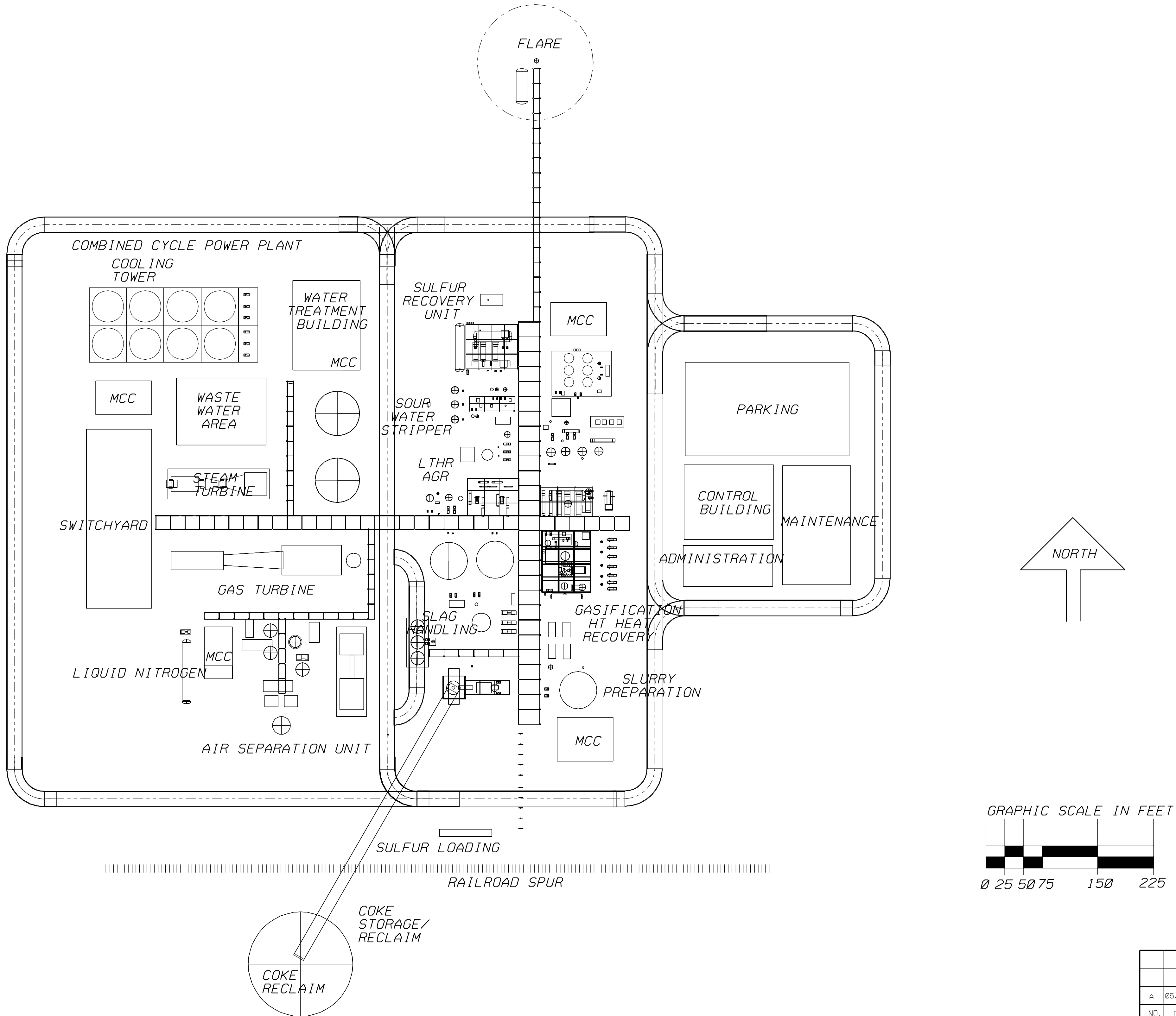
BLOCK FLOW DIAGRAM

File: Fig 3 1.1 R1.xls February 20, 2002

Figure 4

Site Plan for the Subtask 1.5B

Single-Train IGCC Coke Power Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A	05/18/01		DAJ				

SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

COKE IGCC POWER PLANT
SUBTASK 1.5 B

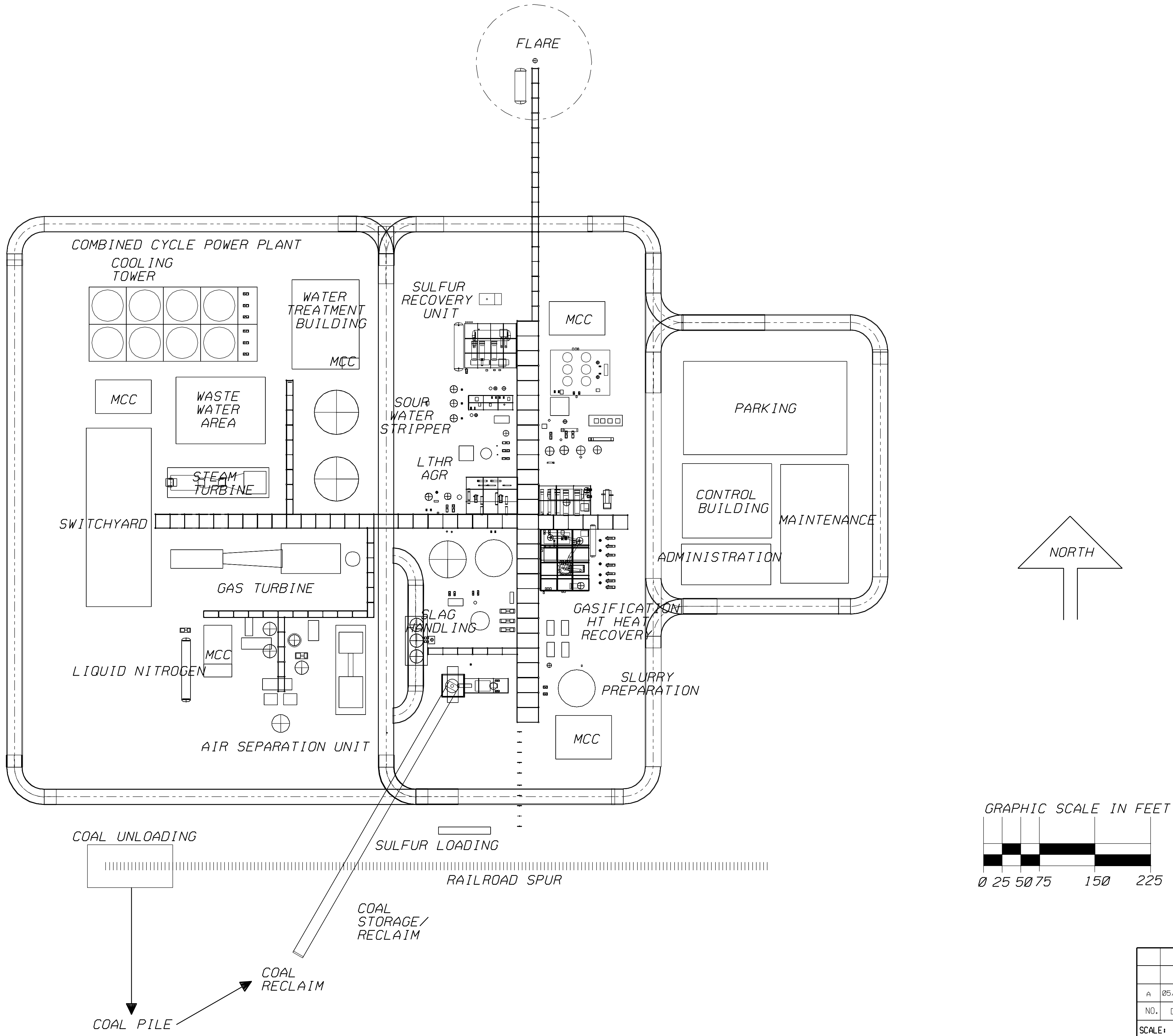
FIGURE 4
SITE PLAN

JOB NO: 24355-104 DRAWING NO: SK - 00015 REV. A

Figure 5

Site Plan for the Subtask 1.5A

Single-Train IGCC Coal Power Plant



A	05/18/01		DAJ				
NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT

SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

COAL IGCC POWER PLANT
SUBTASK 1.5 A

FIGURE 5
SITE PLAN

JOB NO: 24355-104 DRAWING NO: SK - 00016 REV. A

Figure 6

Return on Investment versus Power Selling Price for the Subtask 1.1 and Subtask 1.5 Cases with a 10% Loan Interest Rate

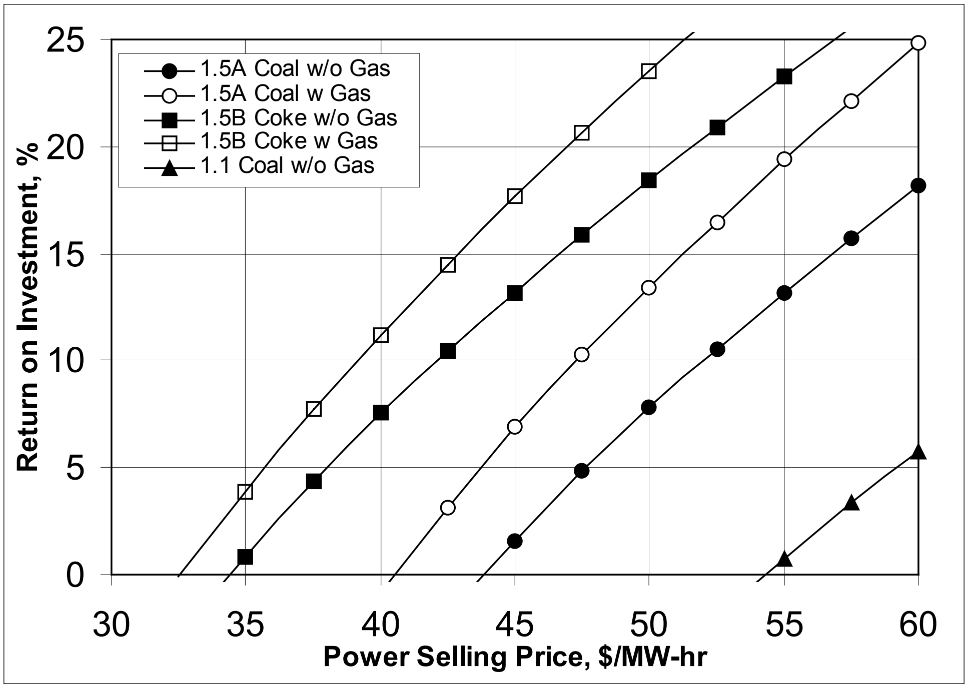
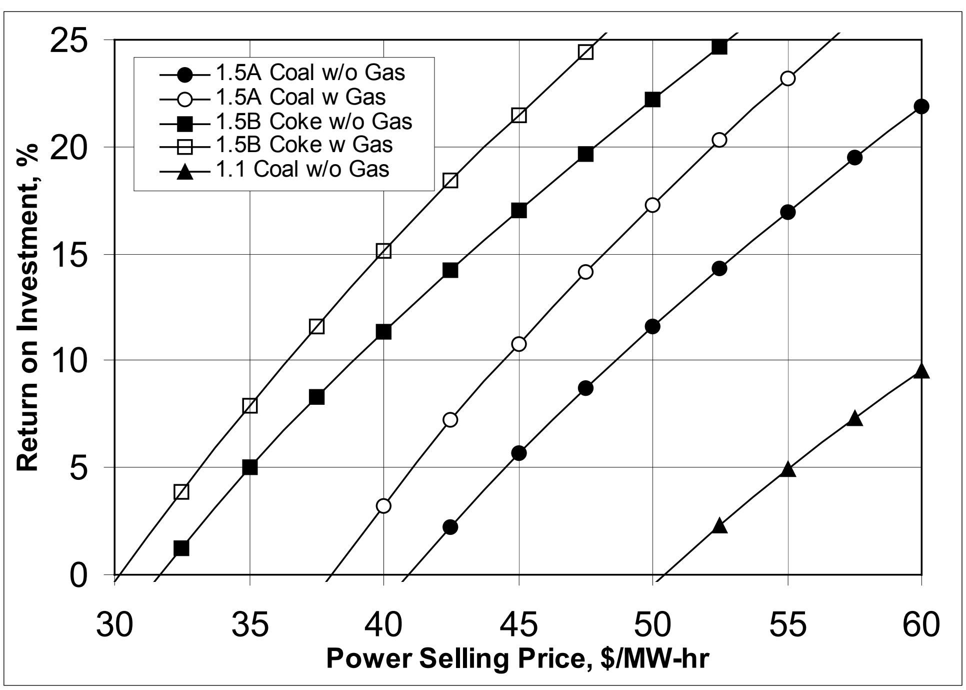


Figure 7

Return on Investment versus Power Selling Price for the Subtask 1.1 and Subtask 1.5 Cases with a 8% Loan Interest Rate



Appendix G - Subtask 1.6

Nominal 1,000 MW Coal IGCC Power Plant

Subtask 1.6

Nominal 1,000 MW Coal IGCC Power Plant

The objective of Subtask 1.6 is to develop a current day design and installed capital cost estimate for an optimized nominal 1,000 MW coal fueled IGCC power plant which incorporates the Value Improving Practices (VIP) results from Subtasks 1.3 and 1.4. The resulting plant is a four-train plant utilizing Global Energy's current gasification technology coupled with General Electric's 7FA+e combustion gas turbine generator.

Subtask 1.3 developed a design and installed capital cost estimate for an optimized Petroleum Coke IGCC Coproduction Plant that is located adjacent to a Gulf Coast petroleum refinery and coproduces hydrogen and steam for the refinery. The Wabash River Repowering Project provided the basic design and cost information for Subtask 1.3. Subtask 1.5 developed designs for single-train coal and coke fueled IGCC power plants based on the Subtask 1.3 design. Subtask 1.4 built upon the results of Subtask 1.3 to develop a design and cost estimate for a (future) Subtask 1.4 Optimized Coal to Power IGCC Plant located at a generic Mid-West site that will use an advanced "H class" combustion turbine. The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant design combines most of the best features of these previous cases.

Design Objectives

The design objectives of this study were to develop a 1,000 MW optimized IGCC coal fueled power plant using Global Energy's E-GAS^{TM} gasifier and General Electric 7FA+e combustion turbines. Design alternatives were evaluated based on present day costs and projected inflation/escalation rates. The end result of this study is a coal-based, base-loaded power plant that can have a 12% return on investment and be economically competitive with power production from natural gas under the current economic scenario. Appendix B contains the basic economic parameters used in this study.

Plant Description

The Subtask 1.6 1,000 MW IGCC Coal Power Plant is four-train IGCC power plant designed to produce 1154.6 MW of electric power from 9,266 TPD of dry Illinois No. 6 coal. It also produces 236.6 TPD of sulfur and 1,423 TPD of slag.[1] Figure A4 of Appendix A is a detailed block flow diagram of the plant showing the major stream flow rates. The plant satisfies all applicable environmental laws. Sulfur removal is over 98.9%. The plant occupies about 62 acres.

Three Air Separation Units (ASU) produce about 8,009 TPD of 95% oxygen which is fed to four Global Energy E-GAS two-stage gasifiers which employ full slurry quench. Char and unreacted coal particles that leave the gasifier second stage in the syngas are collected downstream and recycled back to the first stage of the gasifier. All of the slurry feed is injected into the second stage of the gasifier where it comes in contact with hot syngas leaving the first stage; thus evaporating the slurry water and simultaneously gasifing a portion of the feed. Particulates are

[1] See Appendix A for the coal properties and a detailed description of the plant.

removed from the syngas in a two-step system. First, a hot cyclone removes over 90% of the particulates, and the remainder is removed by an advanced dry char filtration system. The remainder of the gasification plant is similar to the Subtask 1.5A coal plant.

Four General Electric combustion turbines produce 840 MW of power (210 MW each). The heat recovery steam generation (HRSG)/steam turbine systems downstream of the gas turbine produce an additional 465.2 MW of power. The internal power consumption of the plant is about 150.6 MW leaving 1154.6 MW of power for export.

The improved design, economies of scale (attributable to the four-train plant), and the Value Improving Practices (VIP) ideas developed as part of this study are the reasons this plant is larger, more efficient, and significantly less costly on a per unit of export power than the Subtask 1.1 Wabash River Greenfield Plant.

Table 1 shows the major design parameters for the Subtask 1.6 Nominal 1,000 MW Coal IGCC Plant Plant and compares them to two single-train IGCC coal power plants: the Subtask 1.1 Wabash River Greenfield Plant and the Subtask 1.5A IGCC Coal Power Plant. The Subtask 1.5A plant also uses the GE 7FA+e combustion turbine; whereas the Subtask 1.1 Wabash River Greenfield Plant uses the older GE 7FA turbine. The Subtask 1.6 design has a higher design thermal efficiency of 40.0% (HHV basis) compared to the 38.3% thermal efficiency of the Wabash River Greenfield plant. It also requires less oxygen per ton of coal. The design oxygen consumption of the Subtask 1.6 plant is 0.81 tons of pure oxygen/ton of dry coal whereas the Wabash River Greenfield plant consumes 0.89 tons of oxygen/ton of dry coal.

The single-train Subtask 1.5A IGCC Coal Power Plant is an intermediate step between the Subtask 1.1 Wabash River Greenfield Plant and the Subtask 1.6 plant. It contains many, but not all, of the features implemented in the Subtask 1.6 plant. The Subtask 1.5A plant uses a less efficient particulate removal system consisting of a cyclone followed by a wet particulate scrubber to clean the syngas. The single-train Subtask 1.5A plant processes 2,335 TPD of dry coal to produce 284.6 MW of export power at a thermal efficiency of 39.1%. The four-train Subtask 1.6 plant processes 9,266 TPD of dry coal to produce 1154.6 MW of export power at a thermal efficiency of 40% and uses a two-step dry particulate removal system.

The emissions performance of the Subtask 1.6 optimized plant is significantly improved over the Wabash River Greenfield plant. On a per unit of power produced, the CO and NOx emissions from the Subtask 1.6 plant are about the same as the Subtask 1.5A plant because they both use the same GE 7FA+e gas turbine. However, the Subtask 1.6 plant has slightly lower sulfur emissions because of the dry particulate removal system. Table 2 provides a detailed breakdown of the air emissions from the Subtask 1.6, 1.1 and 1.5A plants. All three plants discharge both clear water (from the balance of plant facilities consisting of blowdown from the cooling towers and discharge from the fresh water purification facilities) and a lesser amount of process water.

Value Improving Practices

As part of Subtask 1.3, which developed an optimized petroleum coke IGCC coproduction plant, a Value Improving Workshop (VIP) was held which developed numerous ideas for improving the design of the petroleum coke IGCC plant. Some of these ideas were applicable only to processing coke, some were applicable only to processing coal, and many were applicable to processing either feedstock. Many VIP items, which were applicable to both coal and coke processing, were applied in developing the design for the Subtask 1.6 1,000 MW Coal IGCC

Power Plant. Table 3 lists the major VIP items that were used. Most of these VIP improvements also were included in the single-train Subtask 1.5A IGCC Coal Power Plant. Some additional VIP items which are unproven and will require a significant development effort only are included in the future Subtask 1.4 plant design.

Cost Estimate

The Subtask 1.6 Nominal 1,0000 MW Coal IGCC power Plant is expected to have an "overnight" EPC cost of about 1,231 million mid-year 2000 dollars or about 1,066 $/KW.[2] Table A4 of Appendix A provides a breakdown of the installed cost by plant section. On a cost per unit of export power basis, the Subtask 1.6 plant costs about 19% less than the Subtask 1.5A single-train coal plant and about 36% less than the Wabash River Greenfield Plant.

As the discounted cash flow analysis, will show, this coal IGCC plant can be competitive with new natural gas combined cycle plants at current economic conditions and natural gas costs.

Availability

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[3] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the Subtask 1.4 Optimized Coal to Power IGCC Plant design. Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.6 plant both as only a coal fueled facility and when backup natural gas is used to fire the combustion turbine when syngas is unavailable.[4]

Table 4 presents the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.6 1,000 MW Coal IGCC Power Plant, both with and without the use of backup natural gas, the Subtask 1.1 Wabash River Greenfield Plant, and the single-train Subtask 1.5A Coal Power Plant. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and for the coal feed rates. Both the Subtask 1.1 and 1.5A single-train plants have a spare gasifier vessel in their gasification trains whereas the four-train Subtask 1.6 plant does not contain any spare gasification vessels.

[2] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.
[3] "Wabash River Coal Gasification Repowering Project, Final Technical Report," U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.
[4] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, August 1985.

The Subtask 1.6 plant has a daily average power production rate from syngas of 874.5 MW or about 75.7% of the design capacity. This is slightly better than the average power production capacity from syngas for the Subtask 1.1 plant of 75.5% even though it contains a spare gasification vessel. The improved capacity factor is the direct result of the design improvements developed during the VIP exercise. The power production capacity from syngas for the Subtask 1.5A plant is the highest at 78.2% because of the design improvements and the spare gasifier vessel which allows for the periodic refractory replacement in the off-line vessel while the plant is operating.

With the use of backup natural gas, the capacity factor of the Subtask 1.6 plant increases to 1081.0 MW or 93.6%, which is just above the 93% capacity factor of the Subtask 1.5A plant with backup gas.

Discounted Cash Flow Financial Analysis

A financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[5] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) projects summary result sheets. Appendix B contains the basic model input information used for the Subtask 1.6 financial analysis.

The first line of Table 5 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants with a coal price of 22.0 $/ton dry (0.86 $/MMBtu). (The other basic economic parameters are shown in the middle column of Table 6.) With a 10% loan interest rate and without natural gas backup, the four-train Subtask 1.6 1,000 MW Coal IGCC Power Plant has the lowest required power selling price of 44.37 $/MW-hr (or 4.437 cents/kW-hr) to produce a 12% after-tax return on investment. The single-train Subtask 1.5A Coal to Power Plant requires a 53.89 $/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 67.49 $/MW-hr power selling price for a 12% after-tax return on investment.

With the use of 2.60 $/MMBtu backup natural gas to fire the combustion turbines when syngas is not available, the required power selling prices for a 12% after-tax return on investment are even lower. The Subtask 1.6 case now requires a power selling price of only 40.23 $/MW-hr, and the Subtask 1.5A coal case requires a power price of 48.89 $/MW-hr. Figure 1 shows the return on investment for the Subtask 1.6 and 1.5A plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 10% loan interest rate. This figure graphically shows how the return on investment has increased as a function of the power selling price as a result of the design improvements and operational experience that have been made since the Wabash River Repowering Project was built.

The calculated power selling price is 36.3 $/MW-hr for a natural gas combined cycle power plant (costing 450 $/KW of export power) with 3.00 $/MMBtu natural gas using the same financial

[5] Nexant, Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation," Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

assumptions as given in Appendix B, but with a shorter construction period. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 40.90 $/MW-hr to produce a 12% ROI, about 1.97 $/MWhr greater than that of the natural gas combined cycle plant. At a natural gas price of 3.56 $/MMBtu, the natural gas combined cycle plant will require a power selling price of 40.90 $/MW-hr in order to have a 12.0% ROI.

These power selling prices are competitive with the 2001 EIA projections of an average electric selling price of just over 6 cents/kW-hr for the next two decades.[6]

Table 6 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.6 Optimized Coal to Power IGCC Plant starting from a 12% ROI (with a power price of 40.23 $/MW-hr). Each item was varied individually without affecting any other item. Most sensitivities are based on a ±10% change from the base value except when either a larger or smaller change is used because it either makes more sense or it is needed to show a meaningful result. The power selling price is the most sensitive product price with a 10% increase resulting in a 5.79% increase in the ROI to 17.79%, and a 10% decrease resulting in a 6.53% decrease in the ROI to 5.47%. Changes in the sulfur and slag prices have only a small influence on the ROI.

A decrease in the coal price of 5 $/ton from the base coal price of 22.0 $/ton will increase the ROI by 1.94% to 13.94% and a 5 $/ton increase in the coal price will lower the ROI by 1.98% to 10.02%. A decrease in the natural gas price of 0.26 $/MMBtu from the base natural gas price of 2.60 $/MMBtu will increase the ROI by 0.65% to 12.65% and a 0.26 $/MMBtu increase in the gas price will lower the ROI by 0.66% to 11.34%.

A 5% decrease in the plant EPC cost to 1,170 MM$ will increase the ROI by 0.33% to 12.33%, and a 5% increase in the plant cost to 1,293 MM$ will decrease the ROI by 0.31% to 11.69%.

The loan interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.82% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.07%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.62% to 11.38%, and a 20% increase in the loan amount to 88% will increase the ROI by 1.06% to 13.06%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.47%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.51% to 11.49%.

If the plant performance can be increased by 2.5% by improving the thermal efficiency of the plant so that the daily average power output increases to 1,108 MW from 1,081 MW, then the ROI increases by 1.51% to 13.51%. Conversely, a 2.5% decrease in plant performance, which will reduce the daily average power output to 1,054 MW, will lower the ROI by 1.54% to 10.46%.

Effect of Loan Interest Rate

The second line of Table 6 shows the required power selling prices that will produce an after-tax ROI of 12% for the three IGCC coal to power plants with a 8% loan interest rate. As is the case with the 10% loan interest rate cases, there is an additional 3% financing fee on the amount of the loan. With a 8% loan interest rate and without natural gas backup, the Subtask 1.6 1,000 MW Coal IGCC Power Plant still has the lowest required selling price of 41.34 $/MW-hr (or 4.134

[6] Energy Information Administration, "Annual Energy Outlook With Projections to 2020," U. S. Department of Energy, Washington, DC, www.eia.doe.gov/oiaf/aeo, December, 2000.

cents/kW-hr) to produce a 12% after-tax return on investment. The Subtask 1.5A Coal to Power Plant requires a 50.39 $/MW-hr power selling price, and the Subtask 1.1 Wabash River Greenfield Plant requires a 62.87 $/MW-hr power selling price for a 12% after-tax return on investment.

With 2.60 $/MMBtu HHV backup natural gas, the required power selling prices are further reduced. The Subtask 1.6 case now requires a power selling price of only 37.77 $/MW-hr, and the Subtask 1.5A coal case requires a power price of 45.92 $/MW-hr. Figure 2 shows the return on investment for the Subtask 1.6 and 1.5A plants, both with and without natural gas backup, and the Subtask 1.1 Wabash River Greenfield Plant as a function of the power selling price with a 8% loan interest rate. This figure is similar to Figure 1, but a comparison with it shows how influential the loan interest rate is on the return on investment.

The calculated power selling price is 35.4 $/MW-hr for a natural gas combined cycle power plant with a GE 7FA+e combustion turbine (costing 450 $/KW of export power) with 3.00 $/MMBtu HHV natural gas using the same financial assumptions as given in Appendix B, but with a shorter construction period and an 8% loan interest rate. At the same natural gas price, the coal-fired IGCC power plant will require a power selling price of 38.44 $/MW-hr to produce a 12% ROI, slightly above that of the natural gas combined cycle plant. At a natural gas price of 3.37 $/MMBtu, the natural gas combined cycle plant will require a power selling price of 38.44 $/MW-hr in order to have a 12.0% ROI.

Effect of Syngas Availability

After commissioning all plants undergo a “learning curve” during which problem areas are corrected, inadequate equipment is modified or replaced, and adjustments are made. Consequently, performance improves as measured by increased capacity and/or improved on-stream factors. Figure 3 shows the effect of improved syngas availability on the required power selling price for a 12% ROI. As the syngas availability improves, the amount of supplemental natural gas is reduced causing the difference between the cases with and without natural gas to decrease. At the unattainable 100% syngas availability, there is no difference between the two cases.

For the case without natural gas backup, increasing the syngas availability from 75.74% to 80% reduces the required power selling price for a 12% ROI by about 2.00 $/MW-hr from 44.37 to 42.37 $/MW-hr. With natural gas backup, the reduction is not as great, about 0.92 $/MW-hr from 40.23 to 39.31 $/MW-hr.

Figure 4 shows the effect of Syngas Availability on the return on investment without natural gas backup at a power selling price of 44.37 $/MW-hr. In this case, increasing the syngas availability from 75.7 to 80% increases the return on investment by about 2.5% from 12.0 to 14.5%. This figure points out the strong incentive for designing and building a plant that will have high syngas availability.

Figure 5 shows the effect of syngas availability on the Net Present Value @ 12% without natural gas backup at a power selling price of 44.37 $/MW-hr with the same economic scenario as is used in Figure 4. Increasing the syngas availability from 75.7 to 80% increases the NPV by 70.3 MM$; again justifying the incentive for designing and building a plant that will have a high syngas availability.

Alternate Design Case

In the Subtask 1.6 base case, the availability analysis showed that all four gasification trains would be operating for only about 36% of the time because each gasification train does not contain a spare gasification vessel. Since each vessel will require refractory replacement about every other year which takes about three months, an alternate design case was considered to increase the amount of time when sufficient syngas will be available to fully power the gas turbines. In the Subtask 1.1 and 1.5A designs, a second gasification vessel was added to increase the syngas availability so that one vessel could be operating while the refractory in the other is being replaced.

A different approach was taken in this case; namely, that of increasing the capacity of each gasification train by 33.3% so that three gasification trains operating at full capacity will be able to provide sufficient syngas to fully load the four gas turbines. Thus, the capacity of each syngas train from the slurry feed pumps through the gasification, high temperature heat recovery, and two-stage dry particulate removal areas was increased by one-third. The sizes of the units in all the other areas of the plant were left unchanged. This redesign increased the time when sufficient syngas will be available for firing all four gas turbines from 36% to 42% with only a moderate cost increase in the plant cost of about 43 MM mid-2000 dollars. This is less than the cost of adding either an entire spare gasification train or a spare gasification reactor in each train.

Figure 6 shows the return on investment as a function of the power selling price for both the alternate design case (4 x 33% gasification trains) and the base case (4 x 25% gasification trains) with a 10% loan interest rate. The use of the larger trains significantly increases the return on investment at a given power price. At a 40 $/MW-hr power price, the ROI increases from 6.55% to 12.03% for the cases without backup natural gas. With backup natural gas, the increase is not as great, only about 2%, from 11.65% to 13.64%, and the required power selling price for a 12% ROI is 38.86 $/MW-hr.

With an 8% loan rate, the required power selling prices drop even lower. For the case without backup natural gas, the required power selling price for a 12% ROI drops to 37.27 $/MW-hr, and for the case with backup natural gas, it is 36.35 $/MW-hr

Summary

The objective of Subtask 1.6 was to design a nominal 1,000 MW coal IGCC power plant. The design presented in this report satisfies that objective. It processes 9,266 TPD of dry Illinois No. 6 coal and can produce 1154.6 MW of export power at an EPC cost of 1,231 million mid-year 2000 dollars or 1,066 $/KW of export power. On a per unit of power basis, the emissions performance of this plant is significantly better than the emissions performance of the Subtask 1.1 Wabash River Greenfield Plant and about the same as the single-train Subtask 1.5A IGCC Coal Power Plant.

The economics also are more favorable because of

- The Value Improving Practices that were employed in developing the design
- The use of a newer and larger GE 7FA+e combustion turbine
- Economies of scale

For a 12% return on investment without supplemental natural gas and with a 10% project financing rate, the required export power selling price dropped from 67.49 $/MW-hr for the

Subtask 1.1 Wabash River Greenfield Plant to 53.89 $/MW-hr for the single-train Subtask 1.5A IGCC Coal Power Plant, and to 44.37 $/MW-hr for the Subtask 1.6 1 Power Plant. Compared to the Subtask 1.1 Wabash River Greenfield Plant, this is a savings of over 34%. The use of supplemental natural gas will further reduce the required selling price to 40.23 $/MW-hr for the Subtask 1.6 plant.

In today's current economic situation, an 8% interest loan with a 3% upfront financing fee may be possible. Under these conditions, the required export power selling price to produce a 12% ROI drops to 37.77 $/MW-hr with the use of supplemental 2.60 $/MMBtu HHV natural gas. Without supplemental natural gas the required power selling price is 41.34 $/MW-hr. At these power prices, this coal-fired IGCC power plant can be competitive with new natural gas combined cycle power plants using 3.00 $/MMBtu HHV natural gas.

Table 1

Design Feed and Product Rates for the Subtask 1.6, 1.1 and 1.5A Coal IGCC Power Plants

	Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant	Subtask 1.1 Wabash River Greenfield Plant	Subtask 1.5A Current Design IGCC Power Plant
Number of Gasification Trains	4	1	1
Total No. of Gasification Vessels	4	2	2
Number of Combustion Turbines	4	1	1
Feeds			
Coal, TPD dry	9,266	2,259	2,335
River Water, gpm	9,652	2,281	2,836
Products			
Power, MW	1154.6	269.3	284.6
Sulfur, TPD	236.6	57	60
Slag, TPD	1,23	356	364
Performance			
Oxygen Consumption,			
TPD of 95% O_2	8,009	2,130	1,900
Tons O2/ton dry coal	0.81	0.89	0.81
Water Discharge, gpm			
Process Water	59	120	72
Clear Water*	1,248	643	826
Total Discharge	1,307	763	898
Heat Rate, Btu/kW	8,526	8,912	8,717
Thermal Efficiency, % HHV	40.0	38.3	39.1
Emissions			
SO_2, lb/MW-hr	0.38	1.16	0.50
CO, lb/MW-hr	0.14	0.21	0.14
NOx, lb/MW-hr	0.24	0.60	0.25
Sulfur Removal, %	99.0	96.7	98.5
Plant Area, acres	62	61	40
Installed Cost, million mid-2000 $	1231.3	452.6	375
Installed Cost, $/KW	1,066	1,680	1,318

* Clear water discharge includes a 150 gpm allowance for storm water.

Table 2

Environmental Emissions Summary of the Subtask 1.6, 1.1 and 1.5A Coal IGCC Power Plants*

Case	Subtask 1.6	Subtask 1.1	Subtask 1.5A
Description	1,000 MW Coal IGCC Plant	Wabash River Greenfield Plant	Current Design IGCC Power Plant
Feedstock	Illinois No. 6 Coal	Illinois No. 6 Coal	Illinois No. 6 Coal
Total Gas Turbine Emissions			
GT/HRSG Stack Flow Rate, lb/hr	15,929,100	3,770,200	3,983,500
GT/HRSG Stack Exhaust Temperature, °F	238	238	222
Emissions			
SOx, ppmvd	3	3	3
SOx, as SO_2, lb/hr	95	23	24
NOx, ppmvd (at 15% oxygen, dry)	10	25	10
NOx as NO_2, lb/hr	274	160	69
CO, ppmvd	10	15	10
CO, lb/hr	160	55	40
Incinerator Emissions			
Stack Flow Rate, lb/hr	21,360	22,120	21,870
Stack Exhaust Temperature, °F	500	500	500
Emissions			
SOx, ppmvd	7365	6,662	2,473
SOx, as SO_2, lb/hr	343	290	118
NOx, ppmvd (at 3% oxygen, dry)	40	40	40
NOx as NO_2, lb/hr	1	1	1
CO, ppmvd	50	50	50
CO, lb/hr	1	1	1
Total Plant Emissions			
Exhaust Flow Rate, lb/hr	15,950,500	3,792,300	4,005,300
Emissions			
SOx, ppmvd	15	42	19
SOx, as SO_2, lb/hr	438	312	142
NOx, ppmvd	13	30	13
NOx as NO_2, lb/hr	275	161	69
CO, ppmvd	12	17	13
CO, lb/hr	161	56	41
VOC and Particulates, lb/hr	NIL	NIL	NIL
Opacity	0	0	0
Sulfur Removal, %	98.9	96.8	98.6

* Expected emissions performance

Table 3

Subtask 1.6 VIP and Optimization Items

Plant Section	Description
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Used full slurry quench in the gasifier second stage • Maximized syngas moisturization • Used a cyclone and an advanced dry char filter system to remove particulates from the syngas • Improved the burner design
400/420	Simplified Claus plant, amine, and sour water stripper resulting in lower incinerator emissions
500	• Used a General Electric 7FA+e" gas turbine with 210 MW output and lower NOx • Used steam diluent in the gas turbine to reduce NOx
General	• Bechtel's Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach • Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 4

Design and Daily Average Feed and Product Rates for the Subtask 1.6, 1.1 and 1.5A Coal IGCC Power Plants

	Subtask 1.6 1,000 MW Coal IGCC Power Plant			Subtask 1.1 Wabash River Greenfield		Subtask 1.5A Current Design IGCC Power Plant		
		Daily Average			Daily Average		Daily Average	
	Design	Without Backup Gas	With Backup Gas	Design	Without Backup Gas	Design	Without Backup Gas	With Backup Gas
Feeds								
Coal, TPD dry	9,266	7,018	7,018	2,259	1,705	2,335	1,826	1,826
Natural Gas, Mscfd	0	0	34,961	0	0	0	0	6,929
River Water, gpm	9,752	7,386	NC	2,281	1,722	2,836	2217	NC
Products								
Export Power, MW	1154.6	874.5	1081.0	269.3	203.2	284.6	222.5	264.4
Sulfur, TPD	236.6	179.2	179.2	57	43	60	46.9	46.9
Slag, TPD	1423	1078	1078	356	281	364	284.6	284.6
Performance								
Oxygen Consumption,								
TPD of 95% O_2	8,009	6,066	6,066	2,130	1,608	2,015	1,576	1,576
TPD O_2/TPD dry coal	0.86	0.86	0.86	0.94	0.94	0.86	0.86	0
Water Discharge, gpm								
Process Water	59	45	45	120	91	72	56	56
Clear Water	1248	945	NC	643	485	640	500	NC
Total Discharge	1307	990	NC	763	576	712	557	NC
Heat Rate, Btu/kW	8,526	8,526	8,245	8,912	8,912	8,717	8,717	8,429
Thermal Efficiency, %	40.0%	40.0%	41.4%	38.3%	38.3%	39.1%	39.1%	40.5%
Emissions								
SO_2, lb/MW-hr	0.38	0.38	0.31	1.16	1.16	0.50	0.50	0.42
CO, lb/M-hr	0.14	0.14	NC	0.21	0.21	0.14	0.14	NC
NOx, lb/MW-hr	0.24	0.24	NC	0.60	0.60	0.24	0.24	NC
Sulfur Removal, %	98.9	98.9	98.9	96.8	96.8	98.6	98.6	98.6
Plant Area, acres	62			61		40		
Installed Cost, MM$[2]	1231			452.6		375		
Installed Cost, $/kW	1,066			1,680		1,318		

NC = Not Calculated

Table 5

Required Power Selling Prices for a 12% Return on Investment

	Power Selling Price, in $/MW-hr				
	Subtask 1.6		Subtask 1.5A		Subtask 1.1
Loan Interest Rate	Without Natural Gas	With Natural Gas	Without Natural Gas	With Natural Gas	Without Natural Gas
10%	44.37	40.23	53.89	48.86	67.49
8%	41.34	37.77	50.39	45.92	62.87

Table 6

Sensitivity of Individual Component Prices and Financial Parameters on the Subtask 1.6 Base Case Starting from a 12% ROI

(with a Power Price of 40.23 $/MW-hr and with Backup Natural Gas)

	Decrease				Increase		
	ROI	Value	% Change	Base Value	% Change	Value	ROI
Products							
Power	5.47%	36.207 $/MW-hr	-10%	**40.23 $MW-hr**	+10%	44.253 $/MW-hr	17.79%
Sulfur	11.97%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.03%
Slag	11.73%	-5 $/t	---	**0 $/t**	---	5 $/t	12.27%
Feeds							
Coal	13.94%	-5 $/t	-23%	**22.0 $/t**	23%	5 $/t	10.02%
Natural Gas	12.65%	2.34 $/MMBtu	-10%	**2.60 $/MMBtu**	+10%	2.86 $/MMBtu	11.34%
Financial							
Plant Cost	12.16%	1200.5 MM$	-2.5%	**1231.3 MM$**	+2.5%	1262.1 MM$	11.84%
Plant Cost	12.33%	1169.8 MM$	-5.0%	**1231.3 MM$**	+5.0%	1292.9 MM$	11.69%
Interest Rate	15.82%	8%	-20%	**10%**	+20%	12%	8.07%
Loan Amount	11.38%	72%	-20%	**80%**	+20%	88%	13.06%
Tax Rate	12.47%	36%	10%	**40%**	+10%	44%	11.49%
Performance							
Average Power	10.46%	1054.0 MW	-2.5%	**1081.0 MW**	+2.5%	1108 MW	13.51%
Average Power	8.87%	1027.0 MW	-5.0%	**1081.0 MW**	+5.0%	1135.1 MW	14.97%

Figure 1

Effect of Power Selling Price on the Return on Investment at a 10% Loan Interest Rate (Subtask 1.6 has four 25% gasification trains)

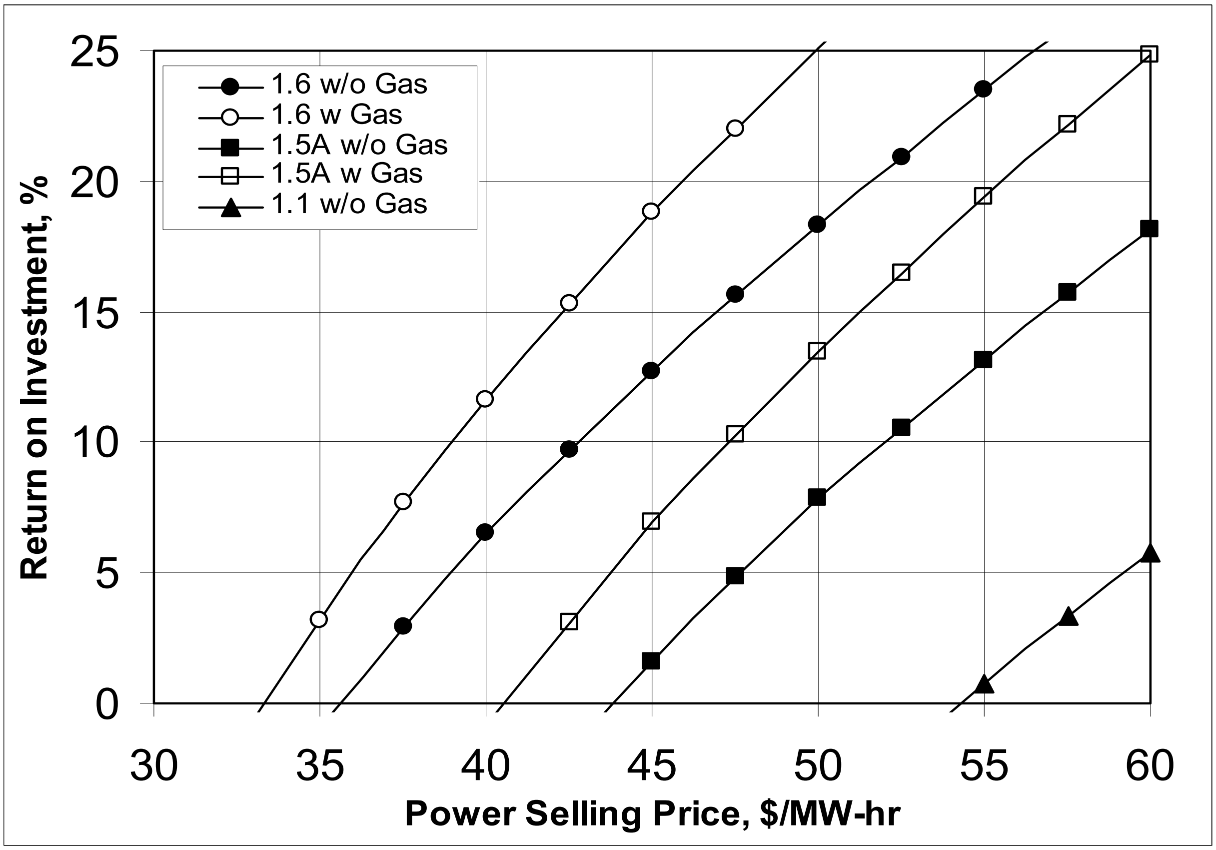


Figure 2

Effect of Power Selling Price on the Return on Investment at a 8% Loan Interest Rate (Subtask 1.6 has four 25% gasification trains)

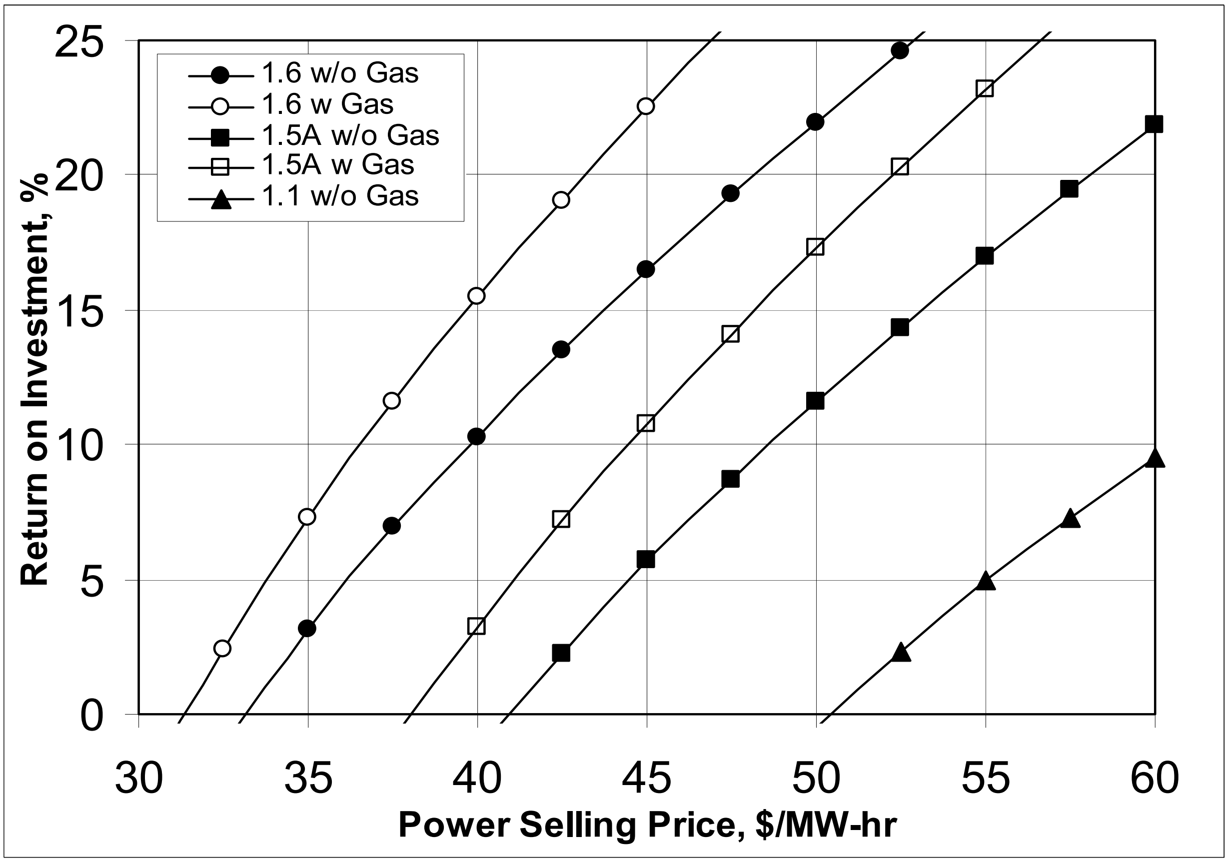


Figure 3

Effect of Syngas Availability on the Required Power Selling Price for a 12% Return on Investment (Subtask 1.6 has four 25% gasification trains)

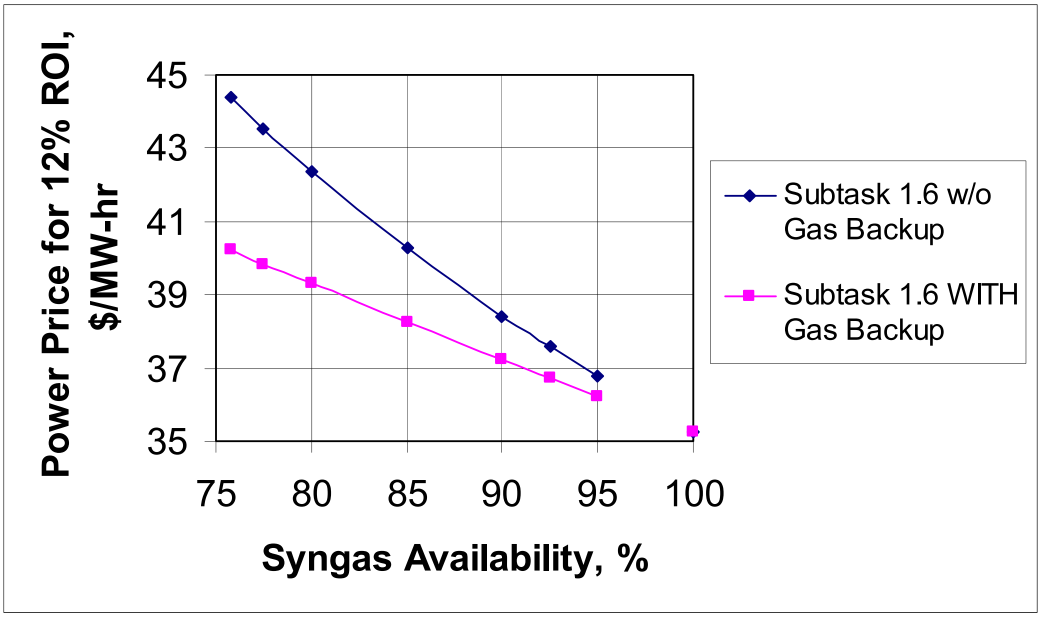


Figure 4

Effect of Syngas Availability on the Return on Investment Without Gas Backup at a Power Selling Price of 44.37 $/MW-hr (Subtask 1.6 has four 25% gasification trains)

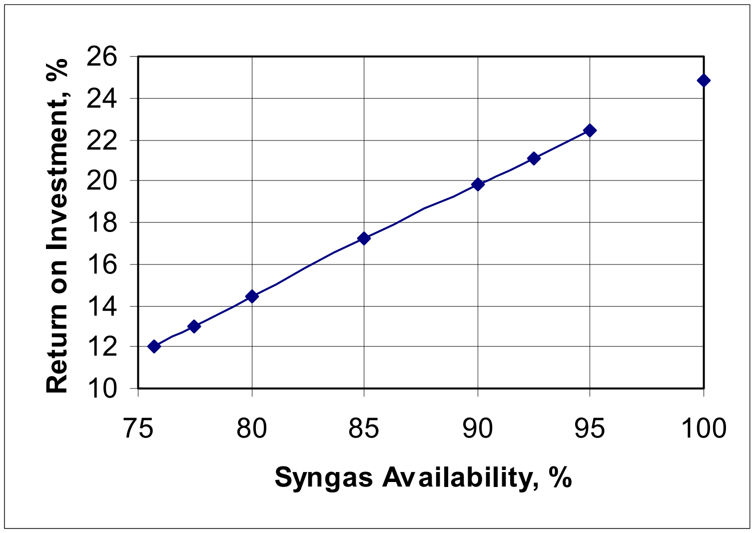


Figure 5

Effect of Syngas Availability on the Net Present Value @ 12% Return on Investment Without Gas Backup at a Power Selling Price of 44.37 $/MW-hr (Subtask 1.6 has four 25% gasification trains)

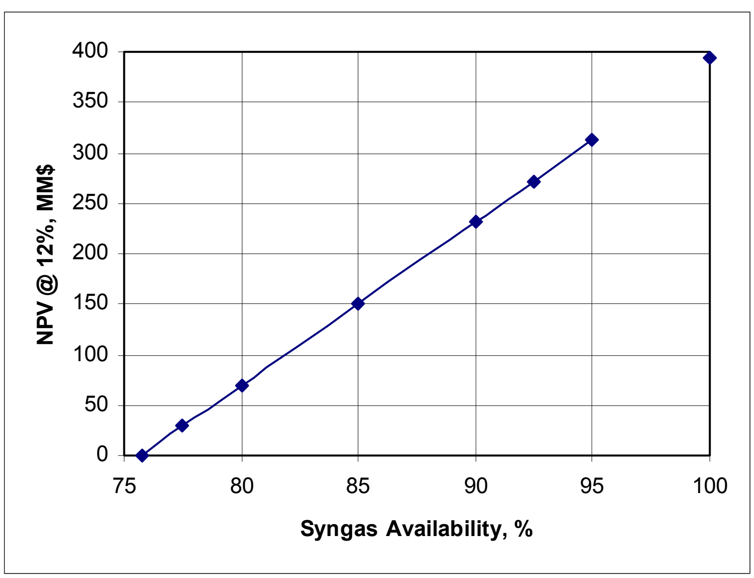


Figure 6

Effect of Power Selling Price on the Return on Investment at a 10% Loan Interest Rate for the Base Case (4 x 25% gasification trains) and for the Alternate Case (4 x 33% gasification trains)

Appendix G

Subtask 1.6 (Appendix A)

Nominal 1,000 MW
Coal IGCC Power Plant

Subtask 1.6 (Appendix A)
Table of Contents

Figures

Appendix A

Subtask 1.6 – The Nominal 1,000 MW Coal IGCC Power Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7FA gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest originally processing Illinois No. 6 coal. Subtask 1.2 developed a design and current cost for a Coal to Power IGCC plant producing electric power, hydrogen, steam, and fuel gas at a Gulf Coast location adjacent to a refinery

Subtask 1.3 optimized the Subtask 1.2 facility to develop an Optimized Petroleum Coke IGCC Coproduction Plant producing electric power, hydrogen and steam at a Gulf Coast location adjacent to a petroleum refinery. The plant design was optimized using both Global Energy's petroleum coke gasification experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures.

Subtask 1.4 developed a design and installed capital cost for a future, highly optimized advanced design coal to power IGCC plant using an advanced gas turbine that is expected to be commercially available for syngas near the end of the decade. This plant incorporates the Value Improving Practices (VIP) results that were developed as part of Subtask 1.3 and several additional items specifically for Subtask 1.4, to create an optimized facility for the production of power from coal.

This appendix summarizes the results of Subtask 1.6. The objective of Subtask 1.6 is to develop a process design and installed capital cost estimate for an optimized nominal 1,000 MW coal fueled IGCC power plant at a generic Illinois site. This plant is to be a four train plant utilizing Global Energy's current gasification technology coupled with General Electric's 7FA+e combustion gas turbine generator. It incorporates the applicable Value Improving Practices (VIP) results from Subtasks 1.3 and 1.4.

Bechtel and Global Energy implemented a project specific Value Improving Practices program to reduce the installed and operating costs associated with the plant to develop the designs for the Subtask 1.3 Petroleum Coke IGCC Coproduction Plants and the Subtask 1.4 Optimized Coal to Power IGCC Plant. The VIP team included process design and construction specialists from Bechtel, gasification experts from Global Energy, and operating and maintenance personnel from the Wabash River Repowering Project. The team implemented Value Improving Practices covering the following areas to improve the plant performance and return on investment.

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Design-to-Capacity
- Traditional Value Engineering
- Process Availability (Reliability) Modeling
- Plant Layout Optimization
- Constructability Review / Schedule Optimization
- Operation and Maintenance and Savings

This appendix contains the following design and cost information:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the coal to power IGCC plant
- Artist's view of the plant
- Overall material, energy and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

The following sections describe the results of the design and cost estimate for the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant.

Section A2 contains the design basis for the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant. Section A3 contains descriptions of the various sections of the plant. Section A4 summarizes the overall plant performance. Section A5 contains a listing of the major pieces of equipment within the plant. Section A6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant. Many design parameters essentially are the same as that of the Subtask 1.5 single train coal IGCC power plant but with a completely dry particulate removal system and several other improvements.

A.2.1 Capacity

The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant processes 9,266 TPD of Illinois No. 6 coal (dry basis) to produce syngas that will fully load four General Electric 7FA+e gas turbine generators at 59°F ambient, 60% relative humidity, and 14.43 psia to produce power. Sulfur and slag are the only coproducts.

A.2.2 Site Conditions

Location	Typical Mid-Western State
Elevation, ft	500
Air Temperature	
Maximum, °F	93
Annual, °F	59
Minimum, °F	-20
Summer Wet Bulb, °F	70
Relative Humidity, %	60
Barometric Pressure, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

A.2.3 Coal

Type	Illinois No. 6	
	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,495
Analysis, wt%		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

A.2.4 Water

Cations	mg/L	As equivalent ppm of CaCO3
Aluminum	0.006	0.033
Arsenic	0.002	
Barium	0.055	0.040
Boron	0.154	
Calcium	74.0	185
Chromium	0.005	
Copper	0.002	0.003
Iron	0.028	0.050
Lead	<0.001	0.000
Lithium	0.006	
Magnesium	26.0	107.1
Manganese	0.009	0.016
Molybdenum	0.008	
Potassium	4.8	6.1
Sodium	33.0	71.9
Selenium	<0.001	
Strontium	0.297	0.339
Vanadium	0.010	
Zinc	0.008	0.012
Total Cations		371

Anions	mg/L	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	245.0	200.9
Chloride	44.0	62.0
Sulfide	79.0	82.2
Nitrate - Nitrogen	4.88	4.0
Phosphorus	0.538	4.482
Fluoride	0.25	0.665
Chloride (add to balance)	12.0	16.9
Total Anions		371

Weak Ions	mg/L	As equivalent ppm of CaCO3
Ammonia Nitrogen	0.132	
Dissolved Silica	7.1	

Other Characteristics	mg/L	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	419	
Standard Conductivity	671	
Total Alkalinity		201
Total Hardness		290
Total Organic Carbon	4 to 11.2	
Turbidity	8 to 100	
PH	7.6 to 8.4	
Total Nitrogen	6.1	
Total Suspended Solids	23 to 336	

A.2.5 Natural Gas

Natural gas will be available for startup and for supplemental firing of the combustion turbines and HRSGs. The natural gas will have a HHV of 1,000 Btu/scf and a LHV of 900 Btu/scf.

A.3 Plant Description

A.3.1 Block Flow Diagram

The Nominal 1,000 MW Coal IGCC Power Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification

  - Slurry Preparation
  - Slag Handling
  - Gasifier/High Temperature Heat Recovery (HTHR)/Cyclone and Dry Char Filter Particulate Removal System
  - Low Temperature Heat Recovery (LTHR)
  - Wet Chloride Scrubber
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block

  - Gas Turbine (GT)/Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator(STG)/Auxiliary Equipment

- Balance of Plant

Figure A1 is the block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the capacity of each train relative to the total design capacity are noted on the BFD.

A.3.2 General Description

The plant is divided into the five distinct areas.

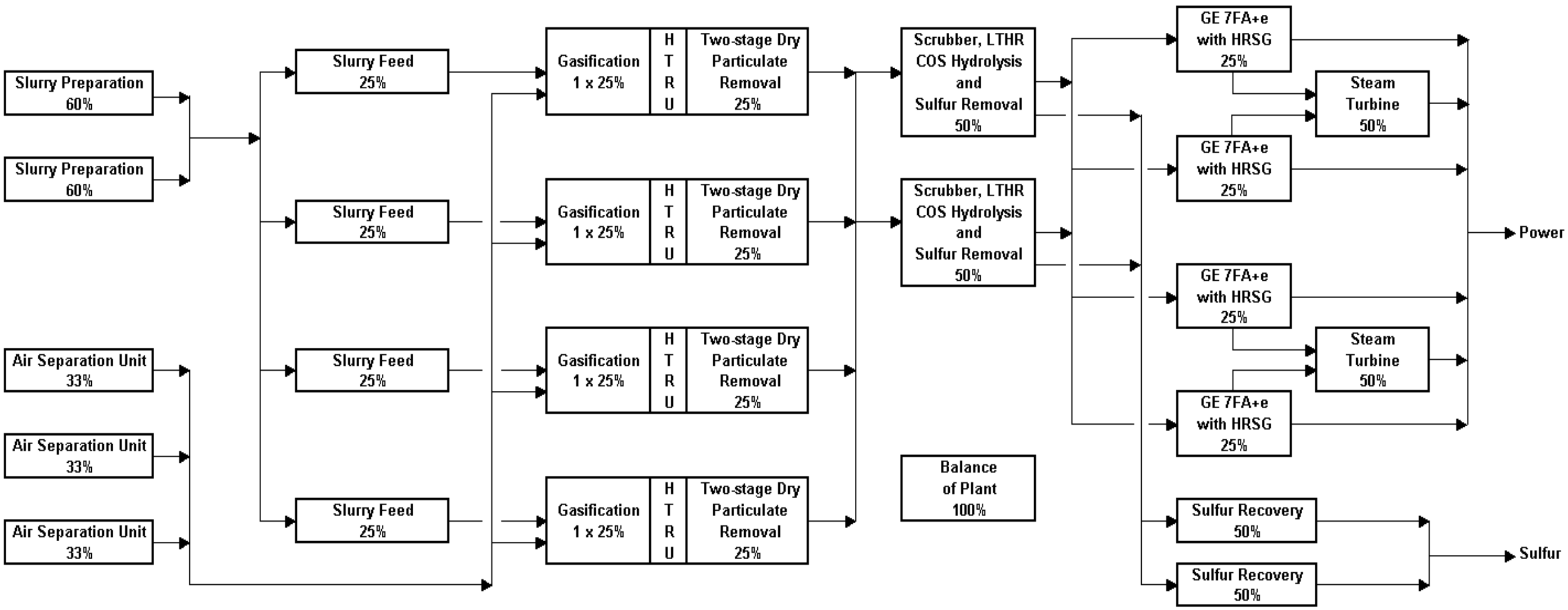
- Fuel Handling Unit
- Gasification Plant
- Air Separation Unit
- Power Block
- Balance of Plant

Section A.3.3 describes the additional fuel handling facilities required for the coal from unloading to on-site storage and conveying to the gasification plant.

Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two-stage entrained flow gasifier to convert the coal to syngas. The gasification plant includes several process units to remove impurities from the syngas; namely a two-stage cyclone/dry char filter system and a wet chloride scrubber system.

Figure A1

Simplified Block Flow Diagram for the Nominal 1,000 MW Coal IGCC Power Plant



Note: Capacity percentages are based on total plant capacity.

Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 95% purity oxygen stream is produced as the oxidant for the gasifier. The ASU is not integrated with the combustion gas turbine.

Section A.3.6 describes the power block, which consists of a four General Electric 7FA+e gas turbines with HRSGs and generators. The gas turbine generators use steam for NOx control.

Section A.3.7 describes the balance of plant (BOP). The BOP portion of the Nominal 1,000 MW Coal IGCC Power Plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Nominal 1,000 MW Coal IGCC Power Plant are shown in Figures A2 and A3 at the end of Section A.3. These figures were generated by the Comet model.

A.3.3 AREA 100 – Fuel Handling

The coal handling system provides the means to receive, unload, store, reclaim, and convey coal to the storage facility. Coal is delivered to the site by rail and transferred to the gasification area through the coal unloading system to the crusher house. Coal also can be delivered by truck and dumped directly onto the coal pile when train deliveries are not available.

Coal is transferred from the crusher house to the active coal storage pile by transfer belt conveyors. Coal is reclaimed from the active coal storage pile to the gasification plant coal silo by variable rate feeder-breakers and the reclaim belt conveyors.

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur recovery. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

Coal slurry feed for the gasification plant is produced by wet grinding in a rod mill. A conveyor delivers the coal into the rod mill feed hopper. Water is added in order to produce the desired slurry solids concentration. The slurry water includes water that is recycled from other areas of the gasification plant. Prepared slurry is stored in an agitated tank.

All tanks, drums and other areas of potential atmosphere exposure of the product slurry or recycled water are closed and vented into the tank vent collection system for control of vapor emissions.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-GAS™ Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a refractory lined vessel into which oxygen and recycle char and unreacted coal are fired via mixer nozzles. The coal slurry, recycle char and oxygen are fed sub-stoichiometrically at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coal is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the coal is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are removed by downstream processing.

Mineral matter in the coal forms a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows upward from the first stage into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which a portion of the coal slurry feed stream is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This coal feed first lowers the temperature of the gas exiting the first stage by the endothermic nature of the reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by evaporation of the water entering with the coal slurry. No oxygen is introduced into the second stage.

The gas and entrained particulate matter (char and unreacted coal) exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

To remove solids from the syngas, the raw gas passes through a two-step particulate removal system consisting of a cyclone located upstream of the high temperature heat recovery unit and a dry char filter system located downstream. The recovered char and unreacted coal particles are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers at the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir at the top of the bin and goes to a settler where the remaining solids are collected. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, water circulation pumps, and a flash gas scrubber to remove residual H_2S. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.4.4 AREA 400

A.3.4.4.1 Low Temperature Heat Recovery

Filtered syngas is scrubbed to remove water-soluble contaminants such as chlorides. The scrubbed syngas is sent to the COS hydrolysis unit. Since COS is not removed efficiently by the downstream Acid Gas Removal (AGR) system, the COS must be converted to H_2S in order to obtain the desired high sulfur removal level. This is accomplished by the catalytic reaction of the COS with water vapor to create hydrogen sulfide and carbon dioxide. The hydrogen sulfide formed is removed in the AGR section and the carbon dioxide goes with the raw syngas to the turbine.

After exiting the COS hydrolysis unit, the syngas is cooled through a series of shell and tube exchangers before entering the AGR system. This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

The heat removed prior to the AGR unit provides moisturizing heat for the product syngas, steam for the AGR stripper, and condensate heat. Cooling water provides trim cooling to ensure the syngas enters the AGR at a sufficiently low temperature. The cooled sour gas is fed to an absorber in the AGR unit where the solvent selectively removes the H_2S to produce a sweet syngas.

A.3.4.4.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a single train with backup sour water feed storage.

A.3.4.4.3 Acid Gas Removal (AGR)

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature using a solvent, methydiethanolamine (MDEA). After the hydrogen sulfide removal, the syngas is moisturized and heated before going to the gas turbine.

The hydrogen sulfide rich MDEA solution exits the absorber and flows to a stripper column where the hydrogen sulfide is removed by steam stripping at lower pressure.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean amine exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Over time the MDEA accumulates impurities, which reduces the H_2S removal efficiency of the MDEA. An online MDEA reclaim unit continuously removes these impurities to improve the system efficiency.

A.3.4.5 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.5 AREA 200 – Air Separation Unit (ASU)

The ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous nitrogen production.

A.3.6 Power Block

The major components of the power block include four gas turbine generators (GTGs), four heat recovery steam generator (HRSGs), two steam turbine generators (STG), and numerous supporting facilities.

A.3.6.1 AREA 500 - Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), and stack

The combustion turbine generators are GE7FA+e machines, each with a nominal 210 MW output. The gas turbines utilize steam injection for $NO_\times$ control. Combustion exhaust gases are routed from the GTGs to the HRSGs and stacks. Natural gas is used as back-up fuel for the gas turbines during startup, shutdown, and short duration transients in syngas supply.

The HRSGs receive the gas turbine exhaust gases and generate steam at the main steam and reheat steam energy levels. They generate high pressure (HP) steam and provide condensate heating for both the combined cycle and the gasification facilities.

Each HRSG is a fully integrated system consisting of all required ductwork and boiler components. Each component is designed for pressurized operation.

The HRSGs boilers include steam drums for proper steam purity and to reduce surge during cold start. Large unheated down comers assure proper circulation in each of the banks. Heat transfer surface is of the extended surface type, with a serrated fin design.

Each stack includes Continuous Emission Monitoring (CEM).

A.3.6.2 AREA 600 - Steam Turbine (ST)

The two reheat, condensing steam turbines include an integrated HP/IP opposed flow section and an axial flow LP section. Turbine exhaust steam is condensed in surface condensers. The reheat design ensures high thermal efficiency and excellent reliability. Each steam turbine produces about 232.6 MW of electric power.

A.3.6.3 Power Delivery System

The power delivery system includes the gas turbine generators output at 18 kilovolts (kV) with each connected through a generator breaker to its associated main power step-up transformer. A separate main step-up transformer and generator breaker is included for the steam turbine generators. The HV switch yard receives the energy from the six generator step-up transformers at 230 kV.

An auxiliary transformer is connected between the gas turbine generator breakers and the step-up transformers. Due to the large auxiliary load associated with the IGCC plant, internal power is distributed at 33 kV from the auxiliary power transformer. The major motor loads in the ASU plants are serviced by 33/13.8 kV transformers. Several substations, with 33/4.16 kV transformers supplying double ended electrical bus, serve the balance of the project loads.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.6.4 Cooling Water System

Two cooling water systems provide the cooling duty for the power block, for the air separation unit, and for the gasification facility. The major components of the cooling water system consist of two cooling towers and circulating water pumps. All plant cooling requirements are provided via a piping loop running both underground and in the pipe rack. The cooling towers are a multi-cell mechanically induced draft towers, sized to provide the design heat rejection at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.7 AREA 900 - Balance of Plant

A.3.7.1 Fresh Water Supply

Industrial river water is filtered for use as the fresh makeup water supply. A demineralizer supplies demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.7.2 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump is available in case of power loss.

A.3.7.3 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in

Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the waste water outfall system.

A.3.7.4 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The system consists of air compressors, air receivers, hose stations, and piping distribution for each unit. Additionally, the instrument air system consists of air dryers and a piping distribution system.

A.3.7.5 Incineration System

The tank vent stream is composed of primarily sweep gas and air purged through various in-process storage tanks that may contain small amounts of other gases such as ammonia and acid gas. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.7.6 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.7.7 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or fiber optics; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, ASU, and the coal handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical gas turbine, steam turbine, generator, and ASU control parameters.

A.3.7.8 Buildings

The plant has a central building housing the main control room, office, training, other administration areas, and a warehouse/maintenance area. Other buildings are provided for water treatment equipment, coal handling, slurry preparation, and the MCCs. The buildings are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment, as appropriate.

A.3.7.9 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the

Nominal 1,000 MW Coal IGCC Power Plant

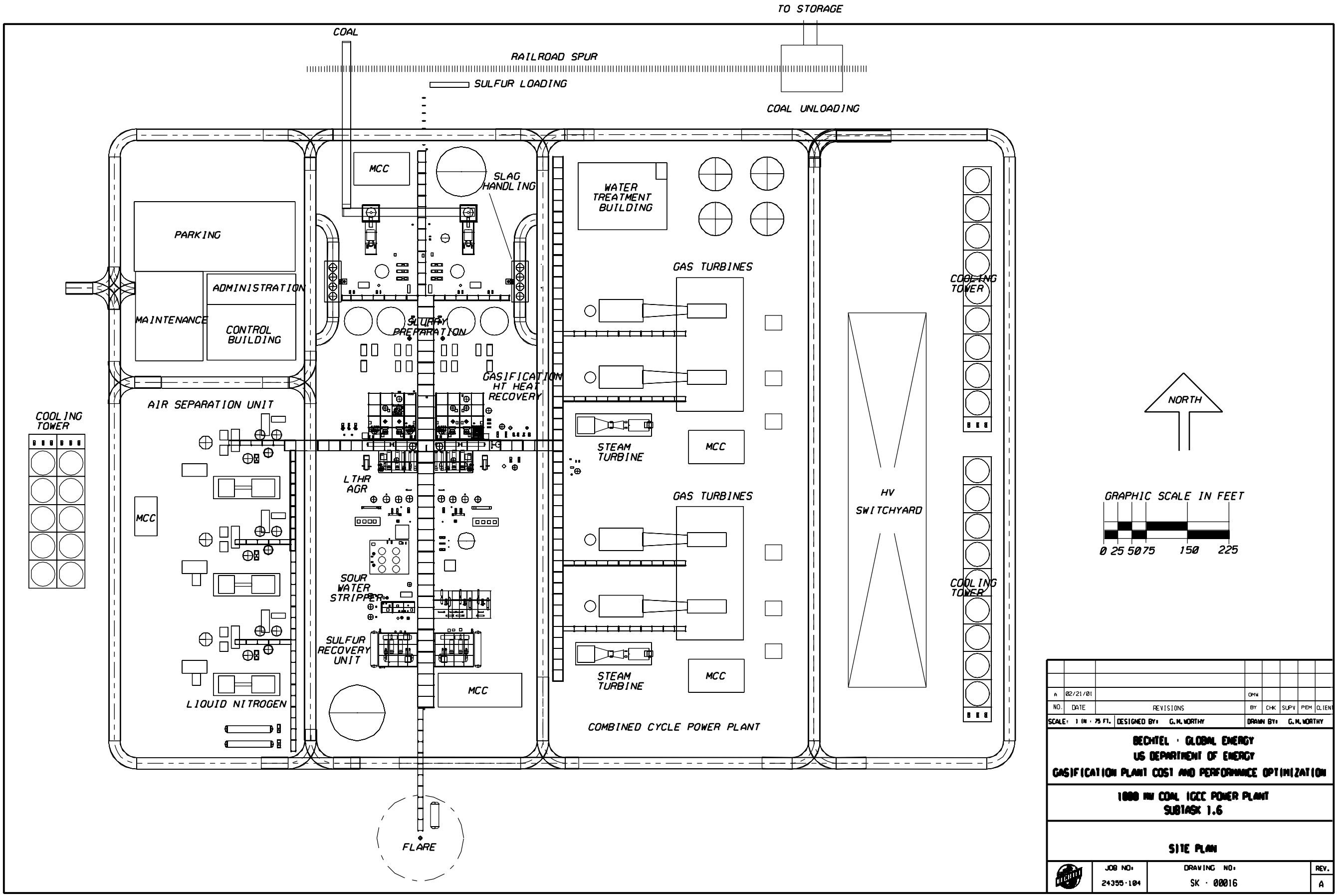
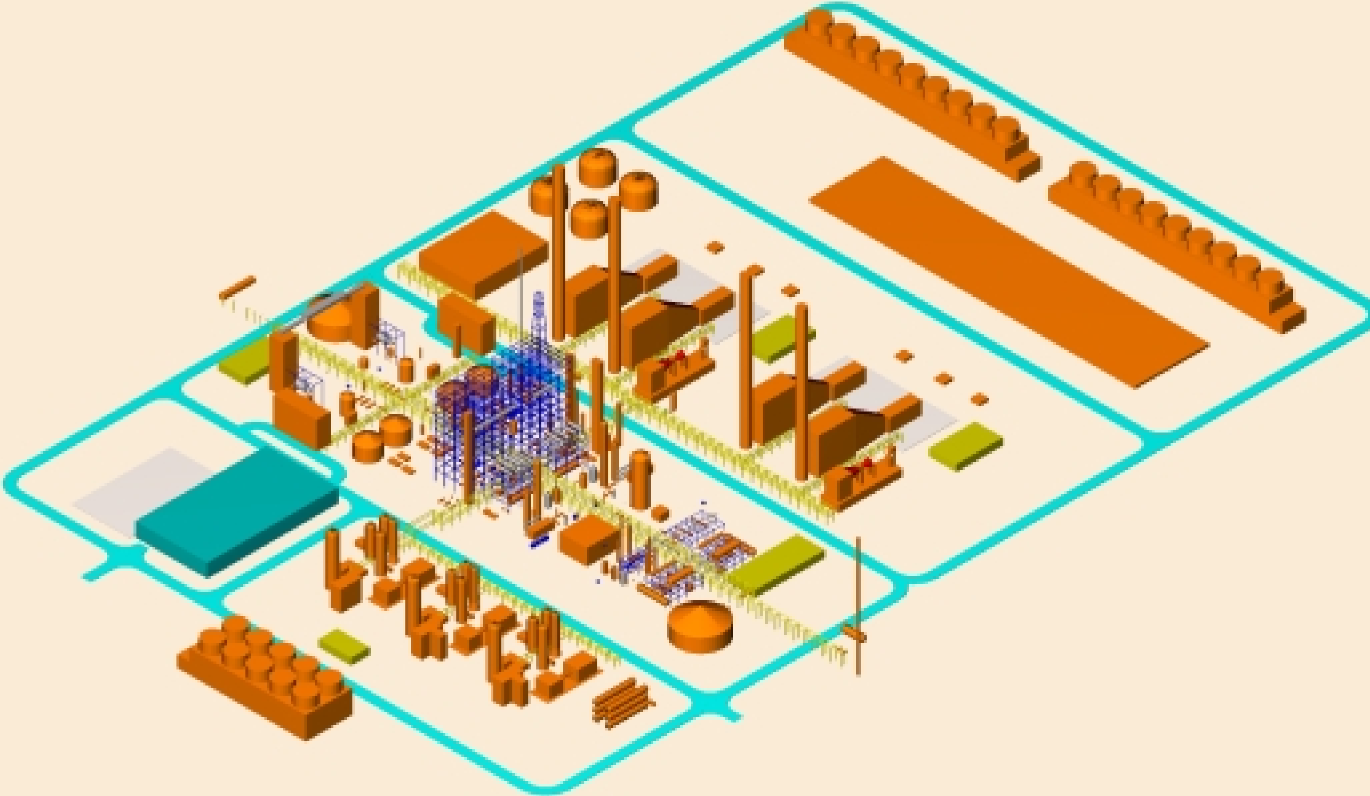

TO STORAGE
COAL
RAILROAD SPUR
SULFUR LOADING
COAL UNLOADING
MCC
SLAG HANDLING
WATER TREATMENT BUILDING
PARKING
ADMINISTRATION
MAINTENANCE
CONTROL BUILDING
SLURRY PREPARATION
GAS TURBINES
COOLING TOWER
GASIFICATION HT HEAT RECOVERY
AIR SEPARATION UNIT
COOLING TOWER
STEAM TURBINE
MCC
NORTH
LTHR AGR
MCC
HV SWITCHYARD
GAS TURBINES
GRAPHIC SCALE IN FEET
0 25 50 75 150 225
SOUR WATER STRIPPER
COOLING TOWER
SULFUR RECOVERY UNIT
STEAM TURBINE
MCC
MCC
LIQUID NITROGEN
COMBINED CYCLE POWER PLANT
FLARE
A 02/21/01 GMW
NO. DATE REVISIONS BY CHK SUPV PEM CLIENT
SCALE: 1 IN = 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY
BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION
1000 MW COAL IGCC POWER PLANT
SUBTASK 1.6
SITE PLAN
JOB NO: 24355-104
DRAWING NO: SK - 00016
REV. A

Figure A3

Artist's Conception of the

Nominal 1,000 MW Coal IGCC Power Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, the Nominal 1,000 MW Coal IGCC Power Plant Detailed Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 9,266 t/d of dry coal and produces 1,154.6 MWe of export electric power, 236.6 t/d of sulfur, and 1423 t/d of slag (containing 15 wt% water). It also consumes 9,652 gpm of river water.

Figure A5 shows the overall water flow diagram for the plant. This figure provides details of the water usage and losses within the plant. The total waste water discharge is about 1,675 gpm which includes an allowance of 150 gpm for rain water.

A.4.2 Performance Summary

Plant performance for the Nominal 1,000 MW Coal IGCC Power Plant is based on Global Energy's heat and material balance using the design basis coal. This information was then integrated with GE 7FA+e combustion turbines, HRSGs, and reheat steam turbines. The GT Pro™ computer simulation program was used to simulate combined cycle performance and plant integration.[1]

Table A1 summarizes the overall performance of the Nominal 1,000 MW Coal IGCC Power Plant. As shown in the table, the oxygen input to the gasifiers is 8,009 t/d of 95% oxygen, and the heat input is 12,749 MMBtu/hr HHV. The gas turbines produce 840 MW of power from their generators. The steam turbines produce another 465.2 MW of power for a total power generation of 1305.2 MW. Internal power usage consumes 150.6 MW leaving a net power production of 1154.6 MW for export.

Table A2 summarizes the expected emissions from the Nominal 1,000 MW Coal IGCC Power Plant. The GE 7FAe+ gas turbine and HRSG systems have a total stack exhaust flow rate of 15,928,800 lb/hr at 238°F. On a dry basis adjusted to 15% oxygen, these gases have a SOx concentration of 3.2 ppmv, a NOx concentration of 10 ppmv, and a CO concentration of 10 ppmv. The incinerator stack has an exhaust flow rate of 21,360 lb/hr at 610°F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 8599 ppmv, a NOx concentration of 40 ppmv, and a CO concentration of 50 ppmv.

The plant emits 15,950,100 lb/hr of total exhaust gases having an average SOx concentration of 15 ppmv, an average NOx concentration of 13 ppmv, and an average CO concentration of 12 ppmv. Expressed another way, this is 438 lb/hr of SOx (as SO_2), 275 lb/hr of NOx (as NO_2), and 161 lb/hr of CO. The sulfur removal is 98.9%.

[1] GT Pro is a registered trademark of the Thermoflow Corporation.

Table A1

Performance Summary of the Nominal 1,000 MW Coal IGCC Power Plant

Ambient Temperature, °F	59
Coal Feed, as received, TPD	10,837
Dry Coal Feed to Gasifiers, TPD	9,266
Total Fresh Water Consumption, gpm	9,752
Sulfur, TPD	236.6
Slag Produced, TPD (15% moisture)	1,423
Total Oxygen Feed to the Gasifier, TPD of 95% O_2	8,009
Heat Input to the Gasifier (HHV), Btu/hr x 10^6	9,844
Cold Gas Efficiency at the Gas Turbine (HHV), %	78.0
Fuel Input to Gas Turbine, lb/hr	1,741,575
Heat Input to Gas Turbine (LHV), Btu/hr x 10^6	7,184
Steam Injection to Gas Turbine, lb/hr	1,037,800
Gas Turbines Output, MW	840
Steam Turbines Output, MW	465.2
Gross Power Output, MW	1305.2
Gasification Plant Power Consumption, MW	(32.4)
ASU Power Consumption, MW	(94.6)
Balance of Plant & Auxiliary Load Power Consumption, MW	(23.6)
Net Power Output, MW	1154.6

Table A2

Environmental Emissions Summary* of the Nominal 1,000 MW Coal IGCC Power Plant

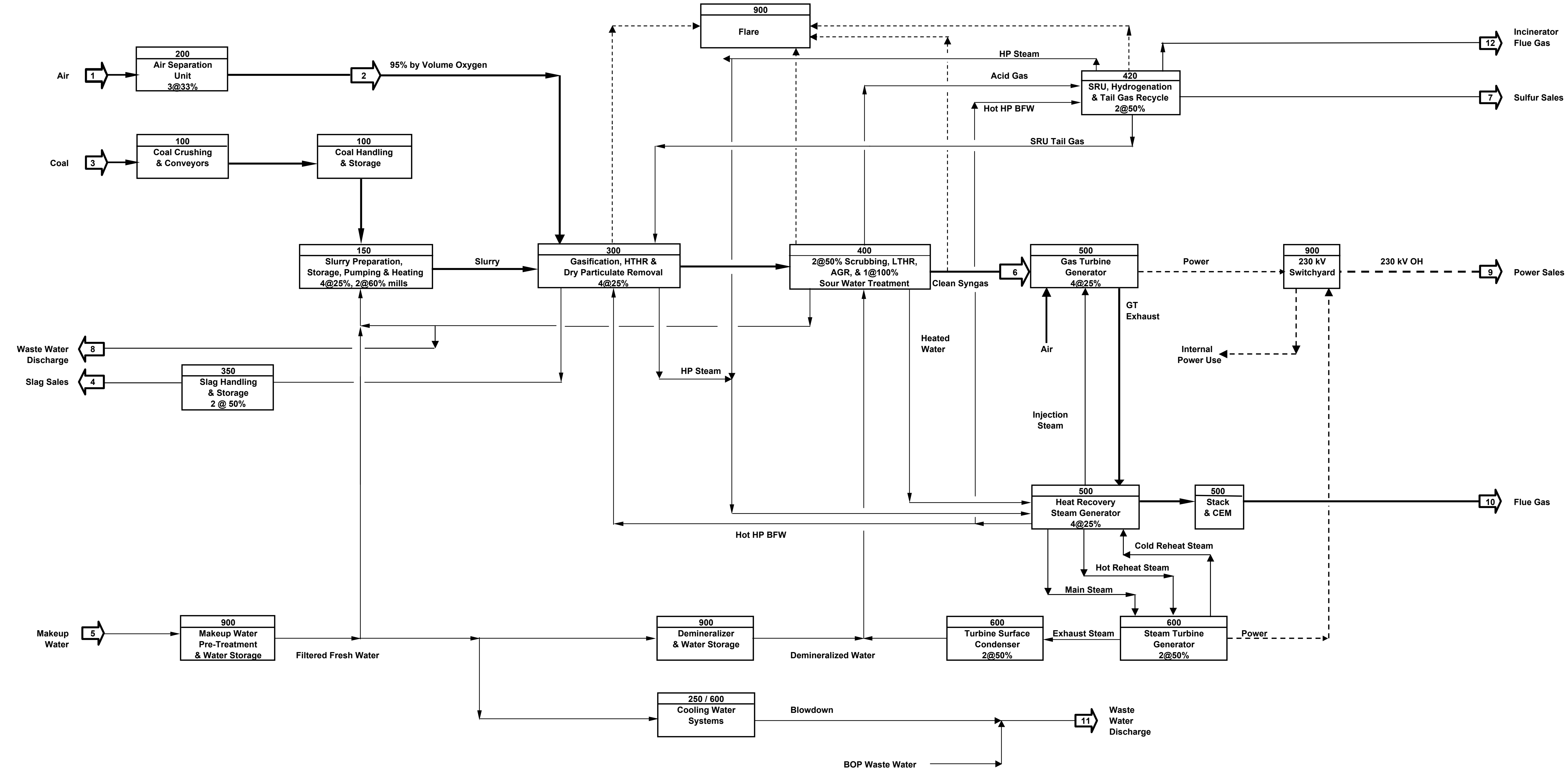
Total Gas Turbine Emissions	
GTs/HRSGs Stack Exhaust Flow Rate, lb/hr	15,928,800
GTs/HRSGs Stack Exhaust Temperature, °F	238
Emissions (at 15% oxygen, dry basis)	
SO×, ppmvd	2.6
SO× as SO_2, lb/hr	95
NO×, ppmvd	10
NO× as NO_2, lb/hr	274
CO, ppmvd	10
CO, lbl/hr	160
Incinerator Emissions	
Stack Exhaust Flow Rate, lb/hr	21,360
Stack Exhaust Temperature, °F	610
Emissions (at 3% oxygen, dry basis)	
SO×, ppmvd	7,365
SO× as SO_2, lb/hr	343.4
NO×, ppmvd	40
NO× as NO_2, lb/hr	0.7
CO, ppmvd	50
CO, lbl/hr	1.0
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	15,950,500
Emissions	
SO×, ppmvd	15
SO× as SO_2, lb/hr	438
NO×, ppmvd	13
NO× as NO_2, lb/hr	275
CO, ppmvd	12
CO, lbl/hr	161
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	98.9

* Expected emissions performance

Figure A4

Detailed Block Flow Diagram of the

Nominal 1,000 MW Coal IGCC Power Plant



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Flow	Air 34,922 Tons/Day	Oxygen 8,009 Tons/Day	Coal 9,266 Tons/Day	Slag 1,423 Tons/Day	Water 4,826,000 Lb/Hr	Syngas 1,741,575 Lb/Hr	Sulfur 236.6 Tons/Day	Water 29,443 Lb/Hr	Power 1,154,600 kWe	Flue Gas 15,934,000 Lb/Hr	Water 624,000 Lb/Hr	Flue Gas 21,359 Lb/Hr									
Nominal Pressure - psig	Atmos.	609	NA	NA	50	350	NA	62	NA	Atmos.	Atmos.	Atmos.									
Temperature - F	59	240	NA	NA	70	530	NA	80	NA	238	NA	500									
HHV Btu/Lb	NA	NA	12,749	NA	NA	4,429	NA	NA	NA	NA	NA	NA									
LHV Btu/Lb	NA	NA	12,275	NA	NA	4,125	NA	NA	NA	NA	NA	NA									
Energy - MM HHV/Hr	NA	NA	9,844	NA	NA	7,714	NA	NA	NA	NA	NA	NA									
Energy - MM LHV/Hr	NA	NA	9,478	NA	NA	7,184	NA	NA	NA	NA	NA	NA									
Notes	Dry Basis	7553 O2	Dry Basis	15%Wtr.	9,652 GPM	to GT	Sales	59 GPM	230 kV		1,248 GPM										

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.6

NOMINAL 1,000 MW COAL IGCC POWER PLANT

BLOCK FLOW DIAGRAM

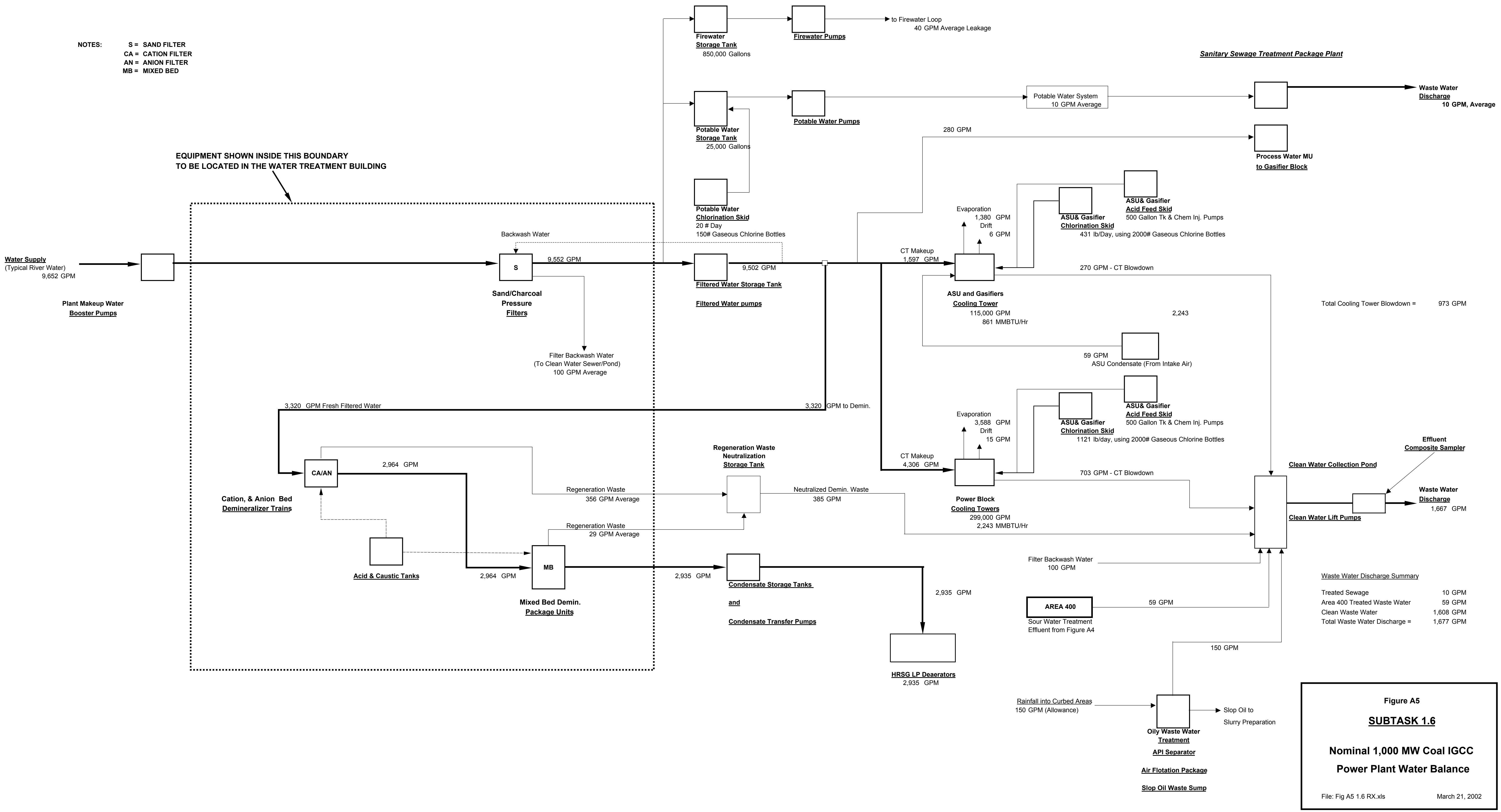
File: Fig A4 1.6 R1.xls

February 20, 2002

Figure A5

Overall Water Flow Diagram of the

Nominal 1,000 MW Coal IGCC Power Plant



NOTES: S = SAND FILTER
CA = CATION FILTER
AN = ANION FILTER
MB = MIXED BED
EQUIPMENT SHOWN INSIDE THIS BOUNDARY
TO BE LOCATED IN THE WATER TREATMENT BUILDING
Water Supply
(Typical River Water)
9,652 GPM
Plant Makeup Water
Booster Pumps
Backwash Water
S
9,552 GPM
Sand/Charcoal
Pressure
Filters
Filter Backwash Water
(To Clean Water Sewer/Pond)
100 GPM Average
Firewater
Storage Tank
850,000 Gallons
Firewater Pumps
to Firewater Loop
40 GPM Average Leakage
Potable Water
Storage Tank
25,000 Gallons
Potable Water Pumps
Potable Water System
10 GPM Average
Potable Water
Chlorination Skid
20 # Day
150# Gaseous Chlorine Bottles
Sanitary Sewage Treatment Package Plant
Waste Water
Discharge
10 GPM, Average
280 GPM
Process Water MU
to Gasifier Block
9,502 GPM
Filtered Water Storage Tank
Filtered Water pumps
Evaporation
1,380 GPM
Drift
6 GPM
ASU& Gasifier
Chlorination Skid
431 lb/Day, using 2000# Gaseous Chlorine Bottles
ASU& Gasifier
Acid Feed Skid
500 Gallon Tk & Chem Inj. Pumps
CT Makeup
1,597 GPM
270 GPM - CT Blowdown
ASU and Gasifiers
Cooling Tower
115,000 GPM
861 MMBTU/Hr
2,243
Total Cooling Tower Blowdown = 973 GPM
59 GPM
ASU Condensate (From Intake Air)
3,320 GPM Fresh Filtered Water
3,320 GPM to Demin.
Evaporation
3,588 GPM
Drift
15 GPM
ASU& Gasifier
Chlorination Skid
1121 lb/day, using 2000# Gaseous Chlorine Bottles
ASU& Gasifier
Acid Feed Skid
500 Gallon Tk & Chem Inj. Pumps
CT Makeup
4,306 GPM
703 GPM - CT Blowdown
Power Block
Cooling Towers
299,000 GPM
2,243 MMBTU/Hr
CA/AN
2,964 GPM
Cation, & Anion Bed
Demineralizer Trains
Regeneration Waste
356 GPM Average
Regeneration Waste
Neutralization
Storage Tank
Neutralized Demin. Waste
385 GPM
Regeneration Waste
29 GPM Average
Acid & Caustic Tanks
MB
2,964 GPM
Mixed Bed Demin.
Package Units
2,935 GPM
Condensate Storage Tanks
and
Condensate Transfer Pumps
2,935 GPM
HRSG LP Deaerators
2,935 GPM
Effluent
Composite Sampler
Clean Water Collection Pond
Waste Water
Discharge
1,667 GPM
Clean Water Lift Pumps
Filter Backwash Water
100 GPM
AREA 400
59 GPM
Sour Water Treatment
Effluent from Figure A4
Waste Water Discharge Summary
Treated Sewage 10 GPM
Area 400 Treated Waste Water 59 GPM
Clean Waste Water 1,608 GPM
Total Waste Water Discharge = 1,677 GPM
150 GPM
Rainfall into Curbed Areas
150 GPM (Allowance)
Slop Oil to
Slurry Preparation
Oily Waste Water
Treatment
API Separator
Air Flotation Package
Slop Oil Waste Sump
Figure A5
SUBTASK 1.6
Nominal 1,000 MW Coal IGCC
Power Plant Water Balance
File: Fig A5 1.6 RX.xls
March 21, 2002

A.5 Major Equipment List

Table A3 lists the major pieces of equipment and systems by process area in the Nominal 1,000 MW Coal IGCC Power Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit, are not available.

Table A3
Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

Fuel Handling – 100
Unit Train Rail Loop
Rotary Coal Car Dumper
Rotary Car Dumper Coal Pit
Rotary Dumper Vibratory Feeders
Rotary Dumper Building & Coal Handling Control Control/Electrical Rooms
Rotary Car Dumper Dust Collector
Rotary Car Dumper Sump Pumps
Coal Car Unloading Conveyor
Coal Crusher
Reclaim Coal Grizzly
Coal Storage Dome
Reclaim Conveyors
Storage/Feed Bins
Reclaim Pit Sump Pumps
Coal Dust Suppression System
Coal Handling Electrical Equipment and Distribution
Electric Hoist
Metal Detector
Magnetic Separator
Vibrating Feeder
Slurry Preparation – 150
Weigh Belt Feeder
Rod Charger
Rod Mill
Rod Mill Product Tank
Rod Mill Product Tank Agitator
Rod Mill Product Pumps
Recycle Water Storage Tank
Recycle Water Pumps
Slurry Storage Tank
Slurry Storage Tank Agitator
Slurry Recirculation Pumps
Solids Recycle Tank
Solids Recycle Tank Agitator
Solids Recycle Pumps
Rod Mill Lube Oil Pumps
Slurry Feed Pumps

Table A3 (Continued)

Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

ASU – 200
Air Separation Unit including:
Nitrogen Compressor
Air Scrubber
Oxygen Compressor
Cold Box (Main Exchanger)
High Temperature Air / Nitrogen Heat Exchanger
Liquid Nitrogen Storage
Gasification - 300
First Stage Mixer
Second Stage Mixer
Gasifier
Post Reactor Residence Vessel
High Temperature Heat Recovery Unit
Hot Cyclone Separator
Slag Pre-Crushers
Slag Crushers
Reactor Nozzle Cooling Pumps
Crusher Seal Water Pumps
Syngas Desuperheater
Nitrogen Heater
Pressure Reduction Units
Dry Char Filters
Cyclone Solids Pickup Vessel
Filter Solids Pickup Vessel
Syngas Scrubber Column
Syngas Scrubber Recycle Pumps
Slag Handling – 350
Slag Dewatering Bins
Slag Gravity Settler
Slag Water Tank
Slag Water Pumps
Gravity Settler Bottoms Pumps
Slag Recycle Water Tank
Slag Feedwater Quench Pumps
Slag Water Recirculation Pumps
Polymer Pumps
Slag Recycle Water Cooler

Table A3 (Continued)

Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

LTHR/AGR – 400
Syngas Recycle Compressor
Syngas Recycle Compressor K. O. Drum
Syngas Heater
COS Hydrolysis Unit
Amine Reboiler
Sour Water Condenser
Sour Gas Condensate Condenser
Sour Gas CTW Condenser
Sour Water Level Control Drum
Sour Water Receiver
Sour Gas K.O. Drum
Sour Water Carbon Filter
MDEA Storage Tank
Lean Amine Pumps
Acid Gas Absorber
MDEA Cross-Exchangers
MDEA CTW Coolers
MDEA Carbon Bed
MDEA Post-Filter
Acid Gas Stripper
Acid Gas Stripper Recirculation Cooler
Acid Gas Stripper Reflux Drum
Acid Gas Stripper Quench Pumps
Acid Gas Stripper Reboiler
Acid Gas Stripper Overhead Filter
Lean MDEA Transfer Pumps
Acid Gas Stripper K.O. Drum
Acid Gas Stripper Preheater
Amine Reclaim Unit
Condensate Degassing Column
Degassing Column Bottoms Cooler
Sour Water Transfer Pumps
Ammonia Stripper
Ammonia Stripper Bottoms Cooler
Stripped Water Transfer Pumps
Quench Column
Quench Column Bottoms Cooler
Stripped Water Transfer Pumps
Degassing Column Reboiler
Ammonia Stripper Reboiler
Syngas Heater
Syngas Moisturizer
Moisturizer Recirculation Pumps

Table A3 (Continued)

Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

Sulfur Recovery – 420
Reaction Furnace/Waste Heat Boiler
Condensate Flash Drum
Sulfur Storage Tank
Storage Tank Heaters
Sulfur Pump
Claus First Stage Reactor
Claus First Stage Heater
Claus First Stage Condenser
Claus Second Stage Reactor
Claus Second Stage Heater
Claus Second Stage Condenser
Condensate Level Drum
Hydrogenation Gas Heater
Hydrogenation Reactor
Quench Column
Quench Column Pumps
Quench Column Cooler
Quench Strainer
Quench Filter
Tail Gas Recycle Compressor
Tail Gas Recycle Compressor Intercooler
Tank Vent Blower
Tank Vent Combustion Air Blower
Tank Vent Incinerator/Waste Heat Boiler
Tank Vent Incinerator Stack
GT / HRSG – 500
Gas Turbine Generators (GTGs), GE 7FA+e Dual Fuel (Gas and Syngas) Industrial Turbine Set, Including: Lube Oil Console, Static Frequency Converter, Intake Air Filter, Compressor, Turbine Expander, Generator Exciter, Mark V Control System, Generator Control Panel and Fuel Skids.
GTG Erection (S/C)
Heat Recovery Steam Generator (HRSG) - Dual Pressure, Unfired, with Integral Deaerator
HRSG Stack (S/C)
HRSG Continuous Emissions Monitoring Equipment
HRSG Feedwater Pumps
HRSG Blowdown Flash Tank
HRSG Atmospheric Flash Tank
HRSG Oxygen Scavenger Chemical Injection Skid
HRSG pH Control Chemical Injection Skid
GTG Iso-phase Bus Duct
GTG Synch Breaker
Power Block Auxiliary Power XformerS

Table A3 (Continued)

Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

Steam Turbine Generator & Auxilaries - 600
Steam Turbine Generatosr (STGs), Reheat, TC2F, complete with Lube Oil Console
Steam Surface Condenser, 316L tubes
Condensate (hotwell) pumps
Circulating Water Pumps
Auxiliary Cooling Water Pumps
Cooling Tower
Balance Of Plant - 900
High Voltage Electrical Switch Yard (S/C)
Common Onsite Electrical and I/C Distribution
DCS
In-Plant Communication System
15KV, 5KV and 600V Switchgear
BOP Electrical Devices
Power Transformers
Motor Control Centers
River Water - Makeup Water Intake and Plant Supply Pipeline
Water Intake System S/C Including;
Intake Structure
Pumphouse
Makeup Pumps
Substation & MCC
Lighting, Heating & Ventilation
Makeup Water Treatment Storage and Distribution
Water Treatment Building Equipment
Hydroclone Clarifier
Coagulation Storage Silo
Clarifier Lime Storage Silo
Gravity Filter
Clear Well
Clear Well Water Pumps
Water Softner Skids
Carbon Filters
Cation Demineralizer Skids
Degasifiers
Anion Demineralizer Skids
Demineralizer Polishing Bed Skids
Bulk Acid Tank
Acid Transfer Pumps
Demineralizer - Acid Day Tank Skid
Bulk Caustic Tank Skid
Caustic Transfer Pumps

Table A3 (Continued)

Equipment List for the Nominal 1,000 MW Coal IGCC Power Plant

Balance of Plant – 900 (Continued)
Demineralizer - Caustic Day Tank Skid
Firewater Pump Skids
Waste Water Collection and Treatment
Oily Waste - API Separator
Oily Waste - Dissolved Air Flotation
Oily Waste Storage Tank
Sanitary Sewage Treatment Plant
Wastewater Storage Tanks
Reverse Osmosis Unit for Chloride Removal
Zero Liquid Discharge Water Evaporation System
Waste Water Outfall
Monitoring Equipment
Common Mechanical Systems
Shop Fabricated Tanks
Miscellaneous Horizontal Pumps
Auxiliary Boiler
Safety Shower System
Flare
Flare K.O. Drum
Flare K.O. Drum Pumps
Chemical Feed Pumps
Chemical Storage Tanks
Chemical Storage Equipment
Laboratory Equipment

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.6 scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 45 months which includes four months of performance testing before full commercial operation. Notice to proceed is based on a confirmed Mid-West plant site and the availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor, and air separation unit.

The project construction schedule of the Nominal 1,000 MW Coal IGCC Power Plant was developed by examining that of the Wabash River Repowering Project and correcting for several problems that were encountered during construction. Furthermore, construction experts were included in the Value Improving Practices team that developed the plant layout so that both ease of construction and maintenance were considered.

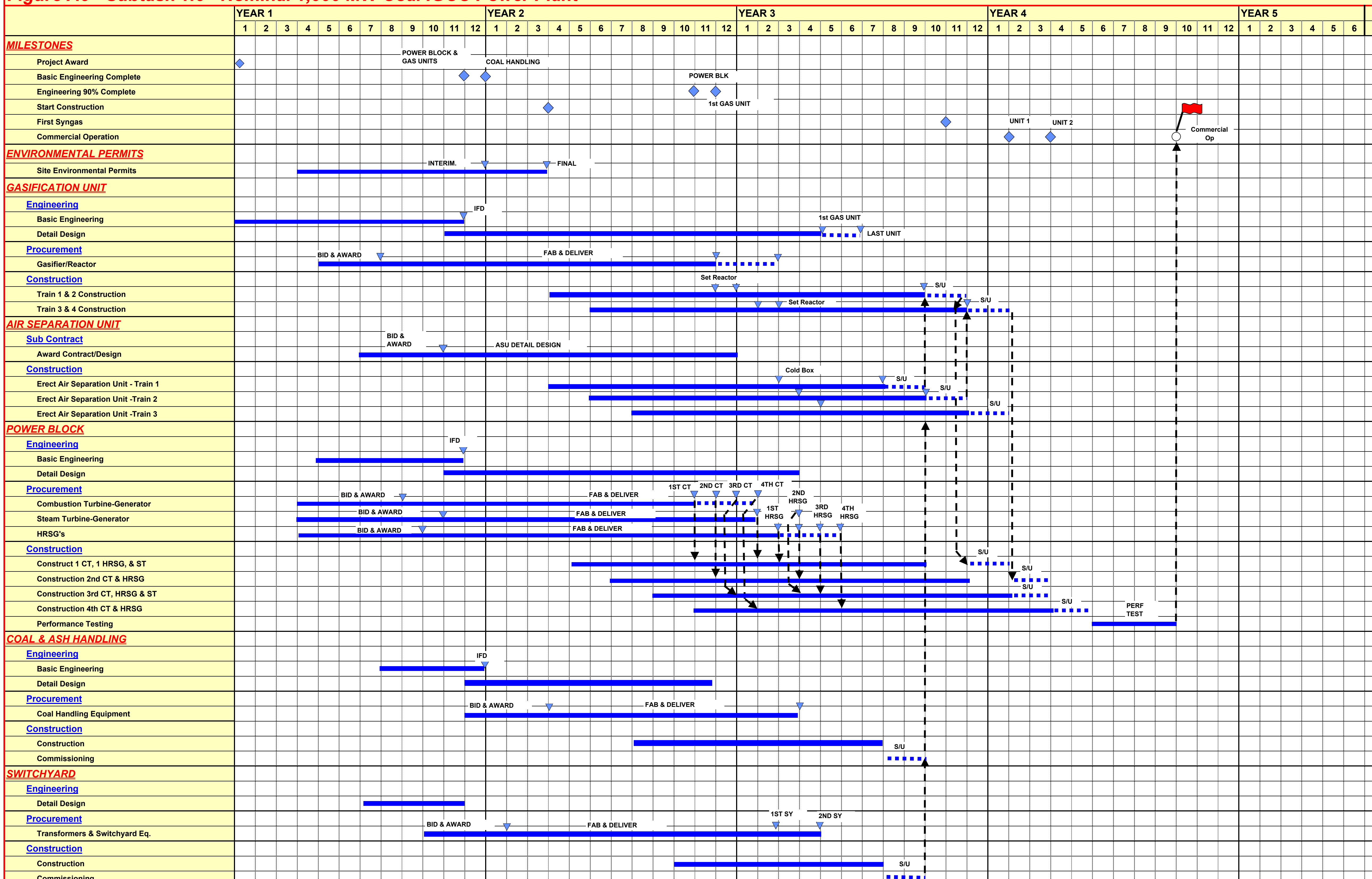
The milestone construction schedule for the major process blocks of the Nominal 1,000 MW Coal IGCC Power Plant is shown in Figure A6.

Figure A6

Milestone Construction Schedule for the

Nominal 1,000 MW Coal IGCC Power Plant

Figure A6 - Subtask 1.6 - Nominal 1,000 MW Coal IGCC Power Plant



BY	DATE	REV.
NS	9/7/01	E
TM	3/26/01	D
TM	9/11/00	C
SO	6/28/00	B
RHS	6/23/00	A

Bechtel
Houston, Texas

US DEPARTMENT OF ENERGY
Gasification Plant Cost & Performance Optimization
Subtask 1.6 - 1,000 MW Coal IGCC Plant
Milestone Schedule

A.6.2 Capital Cost Summary

A.6.2.1. General

The following table illustrates the work breakdown structure (WBS) for Subtask 1.6 and the source of the cost information for each of the areas. The WBS for Subtask 1.6 is the same as that which was used for Subtasks 1.2, 1.3, and 1.4.

WBS	Description	Subtask 1.4
100	Solid Fuel Handling	Bechtel Engineering to provide scope and estimate
150	Slurry Preparation	Adjusted Wabash River and selected quotes
200	Air Separation Unit	Praxair Quote
300	Gasification	Adjusted Wabash River and selected quotes
350	Slag Handling	Adjusted Wabash River
400	Sulfur Removal	Adjusted Wabash River and selected quotes
420	Sulfur Recovery	Adjusted Wabash River and selected quotes
500	GT/HRSG	Based on Bechtel's Powerline™ design and cost information
600	Steam Turbine & Auxiliary Equipment	Based on Bechtel's Powerline™ design and cost information
900	Balance Of Plant	
	High Voltage Switchyard	Bechtel Engineering to provide scope and estimate
	Makeup Water Intake	Bechtel Engineering to provide scope and estimate
	Makeup Water Treatment System	Bechtel Engineering to provide scope and estimate
	Waste Water Collection System	Bechtel Engineering to provide scope and estimate
	Waste Water Discharge	Bechtel Engineering to provide scope and estimate
	Solids Discharge	Used catalyst and waste to landfill
	Piping	By Comet model as calibrated to Wabash River
	Concrete, Steel and Architecture	Wabash River / PSI adjusted for technical basis
	Common Electrical and I&C Systems	Based on Wabash River adjusted for technical basis

Vendor quotes were obtained for most of the new and high price equipment in Subtask 1.4. The power block cost estimate is based on an expected price for the GE 7FA+e gas turbine and Bechtel Powerline™ cost for similar sized power plant currently under construction on the Gulf Coast. Thus, compared to Subtasks 1.1 and 1.2, a much smaller part of the plant costs were estimated based on the Wabash River facility and adjusted for inflation. Mid-West union mid-year 2000 labor rates were used, the same labor rate as was used for Subtasks 1.1 and 1.4 so that this cost estimate is comparable.

This cost estimate is an instantaneous mid-year 2000 cost estimate based on market pricing. There is no forward escalation. As such, it reflects any aberrations in equipment costs based on current market conditions. For example, there is a large demand and backlog for gas turbines so that the current price seems high based on historical data.

Major Equipment

Major equipment from Subtasks 1.1, 1.2, 1.3, and 1.4 was loaded into a data base and modified to reflect the scope of Subtask 1.6. Modifications include changes in equipment duty (as a result of both capacity changes and the Design-to-Capacity VIP), quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

The Design-to-Capacity and Classes of Plant Quality Value Improving Practices were considered in sizing the equipment for this plant. Because coal compositions can be quite variable, a range of coals were considered in the design of the Wabash River Repowering Project to provide feedstock flexibility. In Subtask 1.6, this overdesign was eliminated. Furthermore, some equipment was redesigned to reflect current engineering design practices.

Bulk Materials

Wabash River Repowering Project bulk commodity quantity estimates for steel, concrete, and piping were used as the basis, and then the quantities were adjusted to reflect the scope and site plan for this subtask. Current pricing was used to estimate the costs for the bulk material items.

Subcontracts

Supply and install subcontract pricing was estimated for:

By Budget Quote
- Coal Handling
- Field Erected Tanks
- Air Separation Unit
- Cooling Tower (except basin)

By Unit Pricing
- Buildings including interior finish, HVAC, and Furnishings
- Fire Protection Systems
- Site Development
- Rail Spur

From the Wabash River Facility
- Painting and Insulation
- 230 KV Switchyead
- Gasifier Refractory
- Start-up Services; i.e., flushes and steam blows

Construction

Labor is based on mid-year 2000 Mid-West union shop rates and historic productivity factors. Union labor is used for refractory installation.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.6. Power block costs are based on Bechtel's Powerline™ design and current cost information.

Material Take-off

Subtask 1.1 quantities were used as the basis and adjusted to reflect the scope and site plan for Subtask 1.6, as was done for Subtasks 1.2, 1.3 and 1.4. Modifications were made, as necessary. Concrete, steel and instrumentation were adjusted on an area by area basis reflecting the increased numbers of process trains. The basis for piping adjustment was developed from quantities generated by the COMET model. Electrical quantities were manually adjusted for this subtask.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Design criteria basis are the codes, standards, laws and regulations to be compliant with U. S. and local codes for the designated region typical for U. S. installations and for the designated location of the plant.
- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000. Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- For new and highly priced equipment, current vendor quotes were obtained to reflect current market pricing.
- Site Conditions:
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Coal is delivered by rail on the north side of the site
- Cost includes only areas within the site plan
- Critical spares are included; e.g., proprietary items, one-of-a-kind items, and long lead time items. Normal warehouse, operational, and commissioning/start-up spares are excluded.
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)

The following costs are excluded:

- Contingency and risks
- Cost of permits
- Taxes
- Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
- Facilities external to the site in support of the plant
- Licensing fees
- Agent fees
- Initial fill of chemicals

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Nominal 1,000 MW Coal IGCC Power Plant.

Table A4

Capital Cost Summary of the Nominal 1,000 MW Coal IGCC Power Plant[2]

Plant Area	Direct Field Material			
Solids Handling	15,911,000	10,607,000	1,799,000	28,317,000
Air Separation Unit	91,776,000	57,950,000	1,770,000	151,496,000
Gasification	242,697,000	143,892,000	56,713,000	443,301,000
Power Block	395,898,000	76,251,000	21,646,000	493,795,000
Balance Of Plant	61,411,000	48,637,000	4,371,000	114,419,000
Total	807,693,000	337,337,000	86,298,000	1,231,328,000

Note: Because of rounding, some columns may not add to the total that is shown.

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±15%. The level of accuracy reflects a high degree of confidence based on the large number of vendor quotes that were obtained and that the power block costs are based on a current similar Gulf Coast power project. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

[2] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Appendix G

Subtask 1.6 (Appendix B)

Financial Model Analysis Input

Subtask 1.6 (Appendix B)

Financial Analysis Model Input

Bechtel Technology and Consulting (now Nexant) developed the DCF financial model as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task.[1] This model performs a discounted cash flow financial analysis to calculate investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data directly related to the specific plant as follows.

<u>Data on the Plant Input Sheet</u>

- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table B1 contains the data that are entered on the Plant Input Sheet for the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant both with and without the use of supplemental natural gas.

The Scenario Input Sheet primarily contains data that are related to the general economic environment that is associated with the plant. In addition, it also contains some data that are plant related. The data on the Scenario Input Sheet are shown below.

<u>Data on the Scenario Input Sheet</u>

- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Start up information

Table B2 contains the base case data that are entered on the Scenario Input Sheet for the two Subtask 1.6 cases.

[1] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Table B1
Plant Input Sheet Data for Subtask 1.6

Project Inputs	**Case A**	**Case B**
Project Summary Data		
Project Name / Description	Subtask 1.6 4x25% WITHOUT gas	Subtask 1.6 4x25% WITH gas backup
Project Location	Midwest	Midwest
Project Type/Structure	BOO	BOO
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs	Multiple Outputs
Fuel Type (**Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Petroleum Coke	Petroleum Coke
Plant Input/Output Flowrates - Daily Average Basis (Calendar Day)		
Syngas Capacity (MMscf/day) - Optional	0	0
Gross Electric Power Capacity (MW) - Optional	1,272.8	1,272.8
Net Electric Power Capacity (MW)	874.50	1,081.03
Steam Capacity (Tons/hr)	0.0	0.0
Hydrogen Capacity (MMscf/day)	0.0	0.0
Carbon Monoxide Capacity (MMscf/day) - PSA Tail Gas (Low Btu Fuel Gas)	0.0	0.0
Elemental Sulfur (Tons/day)	179.2	179.2
Slag Ash (Tons/day)	1,077.8	1,077.8
Fuel (Tons/day) - **COAL**	7,018.1	7,018.1
Chemicals - **Natural Gas (Mscf/day) - INPUT**	0	-34,961
Environmental Credit (Tons/day)	0	0
Other (Tons/day) - Flux - **INPUT**	0.0	0.0
Operating Hours per Year	8,760	8,760
Guaranteed Availability (percentage)	100.0%	100.0%
Enter One of the Following Items Depending on Project Type:		
Heat Rate (Btu/kWh) based on HHV - Required for power projects		
Annual Fuel Consumption (in MMcf or Thousand Tons) - Required for non-power projects	2,561.6	2,561.6
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)		
EPC (in thousand dollars)	1,231,328	1,231,328
Owner's Contingency (% of EPC Costs)	5.0%	5.0%
Development Fee (% of EPC Costs)	1.23%	1.23%
Start-up (% of EPC Costs)	1.50%	1.50%
Owner's Cost (in thousand dollars) - Land	$200	$200
Additional Capital Cost - Spares	$18,470	$18,470
Additional Cost #1 - Duties, Taxes, Insurance, etc.	$2,709	$2,709
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent -To be verified during project development. (in thousand dollars)	$61,566	$61,566
Operating Costs and Expenses		
Variable O&M (% of EPC Cost) - **HIGHLY CONFIDENTIAL**		
Fixed O&M Cost (% of EPC Cost) - Staffing - **HIGHLY CONFIDENTIAL**		
Additional Comments: When the average daily input and output flow rates, as calculated by the availability analysis, are supplied, the guaranteed plant availability should be set to 100.0%.	Subtask 1.6 with FOUR 25% Trains WITHOUT natural gas backup. No Spare Train.	Subtask 1.6 with FOUR 25% Trains WITH natural gas backup. No Spare Train.

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 1 of 5)

Project Name / Description	Subtask 1.6 4x25% WITHOUT Gas	Subtask 1.6 4x25% WITH Gas Backup
Project Location	Midwest	Midwest
Project Type/Structure	BOO	BOO

Capital Structure		
Percentage Debt	80%	80%
Percentage Equity	20%	20%
Total Debt Amount (in thousand dollars) - **CALCULATED**	---	---

Project Debt Terms		
Loan 1: Senior Debt		
% of Total Project Debt **(total for Loans 1,2, and 3 must = 100%)**	100%	100%
Loan Amount (in thousand dollars) - **CALCULATED**	---	---
Interest Rate	10%	10%
Financing Fee	3%	3%
Repayment Term (in Years)	15	15
Grace Period on Principal Repayment	0	0
First Year of Principal Repayment	2003	2003
Loan 2: Subordinated Debt		
% of Total Project Debt	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0
Interest Rate	8%	8%
Financing Fee	3%	3%
Repayment Term (in Years)	15	15
Grace Period on Principal Repayment	1	1
First Year of Principal Repayment	2004	2004
Loan 3: Subordinated Debt		
% of Total Project Debt	0%	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0	0
Interest Rate	7%	7%
Financing Fee	3%	3%
Repayment Term (in Years)	10	10
Grace Period on Principal Repayment	1	1
First Year of Principal Repayment	2004	2004

Loan Covenant Assumptions		
Interest Rate for Debt Reserve Fund (DRF)	5%	5%
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	Yes	Yes
Percentage of Total Debt Service used as DRF	20%	20%

Depreciation		
Construction (Years)	7	7
Financing (Years)	7	7

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 2 of 5)

Working Capital		
Days Receivable	30	30
Days Payable	30	30
Annual Operating Cash (in thousand dollars)	100	100
Initial Working Capital (% of first year revenues)	0%	0%

ECONOMIC ASSUMPTIONS

Cash Flow Analysis Period		
Plant Economic Life/Concession Length (in Years)	20	20
Discount Rate	12%	12%

Escalation Factors		
Project Output/Tariff		
Syngas	1.7%	1.7%
Electricity: Capacity Payment	1.7%	1.7%
Electricity: Energy Payment	1.7%	1.7%
Steam	3.1%	3.1%
Hydrogen	3.1%	3.1%
Carbon Monoxide	1.7%	1.7%
Elemental Sulfur	0.0%	0.0%
Slag Ash	0.0%	0.0%
Fuel (IGCC output)	0.0%	0.0%
Chemicals - **Natural Gas**	3.9%	3.9%
Environmental Credit	1.7%	1.7%
Other **- Flux**	1.7%	1.7%
Fuel/Feedstock		
Gas	3.9%	3.9%
Coal	1.2%	1.2%
Petroleum Coke - **Used for COAL in Petroleum Coke Option**	1.2%	1.2%
Other/Waste	2.3%	2.3%
Operating Expenses and Construction Items		
Variable O&M	2.3%	2.3%
Fixed O&M	2.3%	2.3%
Other Non-fuel Expenses	2.3%	2.3%

Tax Assumptions		
Tax Holiday (in Years)	0	0
Income Tax Rate	40%	40%
Subsidized Tax Rate (used as investment incentive)	0%	0%
Length of Subsidized Tax Period (in Years)	0	0

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 3 of 5)

FUEL/FEEDSTOCK ASSUMPTIONS

Fuel Price		
Gas ($/Mcf)	2.60	2.60
Coal ($/Ton)	22.0	22.0
Petroleum Coke ($/ton) - **Used for COAL in Petroleum Coke Option**	22.0	22.0
Other/Waste ($/Ton)	14.00	14.00

Heating Value Assumptions		
HHV of Natural Gas (Btu/cf)	1,000	1,000
HHV of Coal (Btu/kg)	28,106	28,106
HHV of Petroleum Coke (Btu/kg), Dry basis **- Used for Coal**	28,106	28,106
HHV of Other/Waste (Btu/kg)	0	0

TARIFF ASSUMPTIONS

INITIAL TARIFF LEVEL (In Dollars in the first year of construction)		
Syngas ($/Mcf)	$0	$0
Capacity Payment (Thousand $/MW/Year)	$0	$0
Electricity Payment ($/MWh)	$27.00	$27.00
Steam ($/Ton)	$5.60	$5.60
Hydrogen ($/Mcf)	$1.30	$1.30
Carbon Monoxide ($/Mcf)	$0.2274	$0.2274
Elemental Sulfur ($/Ton)	$30.00	$30.00
Slag Ash ($/Ton)	$0	$0
Fuel ($/Ton)	$0	$0
Chemicals **- Natural Gas ($/Mscf)**	$2.60	$2.60
Environmental Credit ($/Ton)	$0	$0
Other ($/Ton) - **Flux**	$5.00	$5.00

CONSTRUCTION ASSUMPTIONS

Construction Schedule		
Construction Start Date	4/1/1999	4/1/1999
Construction Period (in months) - Maximum of 48	45	45
Plant Start-up Date *(must start on January 1)*	1/1/2003	1/1/2003

Percentage Breakout of Cost over Construction Period (each category must total 100%)		
Year 1		
EPC Costs - See Note 1.	19.54%	19.54%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	0%	0%
Start-up Costs	0%	0%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	70%	70%
Additional Capital Costs - Spares	0%	0%
Financing Fee	0%	0%

Table B2
Scenario Input Sheet Data for Subtask 1.4

Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	19.54%	19.54%
Year 2		
EPC Costs - See Note 1.	32.50%	32.50%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	100%	100%
Start-up Costs	0%	0%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	30%	30%
Additional Capital Costs - Spares	0%	0%
Financing Fee	100%	100%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%
Additional Financing Cost A187 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verifi+D192ed during project development. See Note 1.	32.50%	32.50%
Year 3		
EPC Costs - See Note 1.	33.25%	33.25%
Initial Working Capital	0%	0%
Owner's Contingency	0%	0%
Development Fee	0%	0%
Start-up Costs	30%	30%
Initial Debt Reserve Fund	0%	0%
Owner's Cost - Land	0%	0%
Additional Capital Costs - Spares	0%	0%
Financing Fee	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	33.25%	33.25%
Year 4		
EPC Costs - See Note 1.	15.70%	15.70%
Initial Working Capital	100%	100%
Owner's Contingency	100%	100%
Development Fee	0%	0%
Start-up Costs	70%	70%
Initial Debt Reserve Fund	100%	100%
Owner's Cost - Land	0%	0%
Additional Capital Costs - Spares	100%	100%
Financing Fee	0%	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	15.70%	15.70%

Table B2
Scenario Input Sheet Data for Subtask 1.4
(Page 5 of 5)

Plant Ramp-up Option (Yes or No)	Yes	Yes

Start-Up Operations Assumptions (% of Full Capacity)		
Year 1, First Quarter	25.0%	25.0%
Year 1, Second Quarter	50.0%	50.0%
Year 1, Third Quarter	75.0%	75.0%
Year 1, Fourth Quarter	90.0%	90.0%
Year 1 Average Capacity %	60.0%	60.0%
Year 2, First Quarter	100.0%	100.0%
Year 2, Second Quarter	100.0%	100.0%
Year 2, Third Quarter	100.0%	100.0%
Year 2, Fourth Quarter	100.0%	100.0%
Year 2 Average Capacity %	100.0%	100.0%

CONVERSION FACTORS	
kJ to Btu	0.94783
Btu to kWh	3,413
kg to English Ton	1,016
kW per MW	1,000
kJ/kWh	3,600
Gallons Equivalent to 1 Barrel of Crude Oil	42
Cubic Feet to Cubic Meter	0.02832
Months per Year	12
Hours per Day	24
10^6 (for conversion purposes)	1,000,000
Hours per year	8,760

Note 1. The total is greater than 100% to account for inflation during construction.

Appendix H - Subtask 1.7

Coal to Hydrogen Plant

Subtask 1.7

Optimized Coal to Hydrogen Plant

The objective of Subtask 1.7 is to develop a design and installed capital cost estimate for an IGCC coal to hydrogen plant, which incorporates the Value Improving Practices (VIP) results from Subtasks 1.3 and 1,4, where appropriate, at the same coal capacity as Subtask 1.4.

Subtask 1.3 developed designs and installed capital cost estimates for optimized Petroleum Coke IGCC Coproduction Plants that are located adjacent to a Gulf Coast petroleum refinery and coproduce hydrogen and steam for the refinery. The Wabash River Repowering Project provided the basic design and cost information for Subtask 1.3. Subtask 1.4 built upon the results of Subtask 1.3 to develop the Subtask 1.4 Optimized Coal to Power IGCC Plant located at a generic Mid-West site that will use an advanced "H class" combustion turbine. This case established both the size and front end design of the coal to hydrogen plant. The best features of the previous Subtask 1.3 and 1.5 designs have been incorporated into the design of the Subtask 1.7 Coal to Hydrogen Plant.

Design Objectives

The design objectives of this study were to develop an IGCC coal to hydrogen plant producing a maximum amount of 99.0% hydrogen using an enlarged Global Energy gasifier which will process about 3,000 tpd of dry Illinois No. 6 coal. The hydrogen product shall be sulfur and CO_2 free and shall contain no more than 10 ppm by volume of CO. The impurities shall consist of argon, nitrogen and methane. The hydrogen shall be delivered at 1,000 psig.

Plant Description

The Subtask 1.7 Coal to Hydrogen Plant is a large single-train IGCC plant designed to produce 142 MMscfd of 99.0% hydrogen from 3,007 TPD of dry Illinois No. 6 coal. It also produces 76 TPD of sulfur and 474 TPD of slag, and consumes 18.4MW of imported power.[1] Figure A4 of Appendix A is a detailed block flow diagram of the plant showing the major stream flow rates. The plant satisfies all applicable environmental laws. Sulfur removal is 98.5%. The plant occupies about 38 acres. Figure 1 is a simplified block flow diagram of the Subtask 1.7 Coal to Hydrogen Plant

The Air Separation Unit (ASU) produces about 2,522 TPD of 99.5% oxygen.

The gasifier is Global Energy's two-stage gasifier which employs full slurry quench to control the second stage outlet temperature. The full slurry quench gasifier design of Subtask 1.3 was selected rather than the full slurry vaporization design of Subtask 1.4 because it produces more hydrogen and CO (for conversion to hydrogen) rather than methane. In both cases, all slurry water is vaporized in the gasifier. The plant contains a spare gasifier vessel that can be placed in service to minimize the downtime whenever refractory replacement is required.

[1] See Appendix A for the coal properties and a detailed description of the plant.

Char and unreacted coal particles that leave the gasifier in the syngas are collected downstream and recycled back to the first stage of the gasifier. Coal slurry, recycled char and oxygen are fed substoichiometrically into the first stage at elevated temperature and pressure to produce hot, raw syngas. Additional coal and slurry is added in the second stage, lowering the temperature of the gas through quenching and endothermic reactions; thereby, generating more syngas with a higher heating value. Particulates are removed from the syngas in a two-step system. First, a hot cyclone removes over 90% of the particulates, and the remainder is removed by an advanced dry char filtration system.

A Recitsol system is used for acid gas removal rather than an amine system for two reasons. First, it provides better sulfur removal from the syngas than an amine system so that a “sweet” shift process can be used to produce hydrogen from the CO in the syngas. The “sweet” CO shift system has the advantage of allowing higher CO conversions than the “sour” shift process. Secondly, the Rectisol system can be used to removed the bulk of the CO_2 from the shifted syngas for possible sale or sequestration, and it allows the downstream PSA unit to produce a 99.0% pure hydrogen stream containing only trace amounts of CO. However, a Rectisol system is more expensive and auxiliary power intensive than the amine systems that are used for the other subtasks.

The hydrogen production area consists of two parallel trains. Each train contains three CO shift reactors in series with cooling between them. The first two reactors are high temperature shift reactors and are sized to control the maximum outlet temperature. The third reactor is a low temperature reactor for maximum conversion. CO conversion is over 99%.

After the bulk of the CO_2 has been removed by the second stage of the Rectisol unit, two parallel PSA units purify the hydrogen. Hydrogen recovery from the shifted syngas is 90% to the 99.0% pure hydrogen product.

PSA sweep (off) gas is used to generate steam for the steam turbine. Medium pressure steam is extracted from the steam turbine for use in the CO shift reactors. The steam turbine produces 70.6 MW of power. The internal power consumption of the plant is about 87.2 MW. Thus, the plant imports about 18.4 MW of power.

Table 1 shows the design feed and product rates for the Subtask 1.7 Coal to Hydrogen Plant.

Table 2 shows the environmental emissions summary of the Subtask 1.7 Coal to Hydrogen Plant. The CO_2 vent gas emissions are free of SOx and NOx. However, the vent gas contains 0.51 mole% CO. At a 3% oxygen concentration and on a dry basis, the incinerator and steam boiler stack emissions contain 84 ppmv SOx, 40 ppmv NOx, and 50 ppmv CO. Overall, the combination of these two stacks results in total emissions of 37 lb/hr of SOx (as SO_2), 27 lb/hr of NOx (as NO_2), and 1,846 lb/hr of CO. Sulfur removal is 98.5%.

Value Improving Practices

As part of Subtask 1.3, which developed an optimized petroleum coke IGCC coproduction plant, a Value Improving Workshop (VIP) was held which developed numerous ideas for improving the design of the petroleum coke IGCC coproduction plant. Some of these ideas were applicable only to processing coke, some were applicable only to processing coal, and many were applicable to processing either feedstock. Those VIP items, which were applicable to coal processing, were applied in developing the design for the Subtask 1.7 Coal to Hydrogen Plant. Table 3 lists the major VIP items that were used. Most of these VIP improvements also were included in the Subtask 1.3 Next Optimized Petroleum Coke IGCC Coproduction Plant, the Subtask 1.4 Optimized Coal to Power IGCC Plant, the Subtask 1.5 coal and coke power plants, and the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant, as appropriate.

Cost Estimate

The Subtask 1.7 Coal to Hydrogen Plant is expected to cost 529.8 million mid-year 2000 dollars.[2] Table A4 of Appendix A provides a breakdown of the installed cost by plant section. This EPC cost is about 3.7 MM$ per MMscfd of hydrogen production.

Cost reductions could be obtained by relaxing the CO specification in the product hydrogen thereby allowing the use of a lower cost MDEA acid gas removal system. The cost of the hydrogen plant on a per unit of hydrogen also could be lowered by building larger, multiple train plants or coproduction plants where the major product is electric power as was done in the Subtask 1.3 designs.

Availability

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[3] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the Subtask 1.7 IGCC Coal to Hydrogen Plant design using the EPRI recommended procedure.[4] Table 4 presents the design (stream day), average availability, and average daily (calendar day) input and product rates for the Subtask 1.7 IGCC Coal to Power Plant. As the table shows there are significant differences between the calendar day rates and the stream day rates for all the input and output flows. The average hydrogen production rate is 116.7 MMscfd or 81.32% of the design rate.

Discounted Cash Flow Financial Analysis

A financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE as part of

---

[2] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs). It also assumes that process effluent discharge is permitted for all plants except the Subtask 1.4 Optimized Coal to Power IGCC Plant.

[3] "Wabash River Coal Gasification Repowering Project, Final Technical Report," U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

[4] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, August 1985.

the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[5] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) projects summary result sheets. Appendix B contains the basic model input information used in the Subtask 1.7 financial analysis.

At the basic model economic conditions shown in Appendix B, the Subtask 1.7 plant requires a hydrogen selling price of 2.790 $/Mscf to generate a 12% return on investment. These conditions are based on an 80% loan amount at a 10% interest rate with a 3% up front financing fee.

Table 5 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.7 Coal to Hydrogen Plant starting from a 12% ROI (with a hydrogen price of 2.79 $/Mscf). Each item was varied individually without affecting any other item. Most sensitivities are based on a ±10% change from the base value except when either a larger or smaller change is used because it either makes more sense or it is needed to show a meaningful result. The hydrogen selling price has the greatest impact on the ROI with a 10% increase resulting in a 4.32% increase in the ROI to 16.32%, and a 10% decrease resulting in a 4.59% decrease in the ROI to 7.41%. Changes in the sulfur and slag prices have only a small influence on the ROI.

A 10% decrease in the dry coal price of 2.2 $/ton from the base coal price of 22.0 $/ton to 19.8 $/ton will increase the ROI by 0.62% to 12.62%, and a 10% increase in the coal price to 24.2 $/ton will lower the ROI by 0.62% to 11.38%. A 10% change in the imported power price has a lesser effect on the ROI.

A 5% decrease in the plant EPC cost to 503.3 MM$ will increase the ROI by 1.59% to 13.58%, and a 5% increase in the plant cost to 556.3 MM$ will decrease the ROI by 1.45% to 10.55%. A 10% change in the plant cost will have about double the effect of a 5% change

The loan interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.30% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.68%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.52% to 11.48%, and a 20% increase in the loan amount to 88% will increase the ROI by 0.83% to 12.83%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.48%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.52% to 11.48%.

<u>Effect of Loan Interest Rate</u>

At a 8% loan interest rate and with the 3% up front financing fee, a 12.0% ROI can be obtained at a hydrogen selling price of 2.590 $/Mscf. This is a drop of 0.20 $/Mscf from the 2.790 $/Mscf price required with a 10% loan interest rate. Figure 2 shows the effect of the hydrogen selling price on the ROI for the Subtask 1.7 Coal to Hydrogen Plant at both 8% and 10% loan interest rates. The two curves are very similar with the ROI for the 8% loan interest rate being about 3.3% higher than that for the 10% loan interest rate.

[5] Nexant, Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation," Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

Figure 3 shows the effect of the hydrogen selling price on the net present value at a 12% discount rate for the plant. As expected the NPVs for the 8% loan interest rate cases are higher than those for the 10% loan interest rate cases. Again, the curves are similar with the 8% loan interest rates having NPVs that are about 40 MM$ higher than those for the corresponding 10% loan interest rates.

Effect of Syngas Availability

After commissioning all plants undergo a "learning curve" during which problem areas are corrected, inadequate equipment is replaced, and adjustments are made. Consequently, performance improves as measured by increased capacity and/or improved on-stream factors. At a 10% loan interest rate, Figure 4 shows the effect of improved hydrogen availability on the ROI for the Subtask 1.7 plant. Increasing the hydrogen availability from the expected 81.3% to 85% at a hydrogen selling price of 2.79 $/Mscf increases the ROI to 13.68% from 12%.

At a 10% loan interest rate, Figure 5 shows the effect of improved hydrogen availability on the Net Present Value at a 12% discount rate and a hydrogen price of 2.79 $/Mscf. Increasing the hydrogen availability from 81.3% to 85% increases the NPV by 22.4 MM$.

Figure 6 shows the effect of improved hydrogen availability on the required hydrogen selling price for a 12% ROI for both 8% and 10% loan interest rates. Increasing the hydrogen availability from 81.3% to 85% reduces the required hydrogen selling price by about 0.10 $/Mscf in each case.

These three figures show the importance of designing, constructing and operating the plant so that it has a high hydrogen availability. Care should be taken in the design and selection of process equipment so that they will have a high reliability and require minimum scheduled downtime for maintenance.

Effect of Plant Cost

Figure 7 shows the effect of the plant EPC cost on the required hydrogen selling price for the plant to produce a 12% return on investment. At a 10% loan rate, a 5% reduction in the plant EPC cost from 529.8 MM$ to 503.3 MM$ will reduce the required hydrogen selling price from 2.790 $/Mscf to 2.695 $/Mscf, a reduction of about 0.09 $/Mscf or 3.4%. At a 8% loan interest rate, a 5% reduction in the EPC cost reduces the required hydrogen selling price from 2.590 $/Mscf to 2.505 $/Mscf, a reduction of about 0.08 $/Mscf or 3.3%.

Summary

The objective of Subtask 1.7 was to design a single-train, IGCC coal to hydrogen plant. The design presented in this report satisfies that objective. It processes 3,007 TPD of dry Illinois No. 6 coal and produces 142.1 MMscfd of 99.0% hydrogen at 1,000 psig. It has an installed cost of 529.8 million mid-year 2000 dollars.

For the plant to generate a 12% ROI, the required hydrogen selling price must be in the 2.50 to 2.80 $/Mscf range. The exact value depends upon the financing assumptions. These hydrogen prices are about twice the $1.30 Mscf value used for the financial evaluations of the Subtask 1.2 and Subtask 1.3 cases recognizing that the hydrogen produced in this case has a higher purity specification. This 1.30 $/Mscf cost is based in-house information which estimated the cost of hydrogen produced by steam reforming of methane (natural gas) from natural gas or fuel gas priced at 2.60 $/MMBtu or by recovery from hydrogen rich refinery vent gases. In 1998, another study estimated the cost of hydrogen by steam reforming of natural gas at about 2.00 $/Mscf.

There are several possibilities for reducing the required hydrogen selling price.

First, the hydrogen purity specification can be relaxed allowing a higher concentration of oxygen containing impurities in the hydrogen. This would not be harmful if the hydrogen were to be used for hydrotreating in a refinery environment, but could be detrimental for certain petrochemical applications. In this situation, the Rectisol system would be replaced by an amine system, a "sour" shift would be employed, the hydrogen production would be reduced by 9.4%, the plant would become a net electric power producer exporting 39 MW, and the capital cost would be reduced by about 58 MM$. The net effect is that the required hydrogen selling price for a 12% ROI would drop by about 0.19 $/Mscf to 2.60 $/Mscf with a 10% loan interest rate.

Second, switching to the use of a lower cost fuel, such as petroleum coke, as was used in the Subtask 1.2 and 1.3 cases. Approximating this situation by using a zero cost coal would reduce the required hydrogen selling price for a 12% ROI by about 0.40 $/Mscf.

Third, instead of using a single gasification train with a spare gasifier vessel, a complete spare gasification train (without a spare gasifier vessel) could be installed to increase the hydrogen availability. Although this would increase the plant cost, the hydrogen availability would be increased to about 91.7%, and the required hydrogen selling price for a 12% ROI would drop by about 0.11 $/Mscf to 2.684 $/Mscf. The economy of this design philosophy was demonstrated as part of the Subtask 1.3 studies.

Fourth, if the plant were located where the captured CO_2 could be utilized for enhanced oil recovery, the economics would be substantially improved. Assuming the CO_2 could be sold for 12 $/ton, the required hydrogen selling price for a 12% ROI would drop by about 0.6 $/Mscf to 2.194 $/Mscf.

By combining three of the above cases (1. the zero cost feedstock, 2. the increased availability of a spare gasification train, and 3. the opportunity to sell CO_2 for enhanced oil recovery) with an 8% loan rate will significantly reduce the required hydrogen selling price for a 12% ROI to 1.49 $/Mscf.

Building a larger plant with the coproduction of power (similar to that of Subtask 1.3) should allow the advantages of economies of scale primarily by reducing the apportioned cost of the utilities and other OSBL areas that are attributable to the hydrogen plant. Also, a multiple train plant would provide a more reliable source of some hydrogen (although not at the rated capacity) since it is unlikely that the entire plant would be shut down at the same time. This should make the cost of hydrogen competitive with that from steam methane reforming of natural gas.

Table 1

Design Feed and Product Rates for the Subtask 1.7 Coal to Hydrogen Plant

Ambient Temperature, °F	59
Coal Feed, as received, TPD	3,517
Dry Coal Feed to Gasifiers, TPD	3,007
Total Fresh Water Consumption, gpm	2,457
Hydrogen, 99.0%, MMscfd	142.1
Sulfur, TPD	76.4
Slag Produced, TPD (15% moisture)	474.3
Total Oxygen Feed to the Gasifier, TPD of 99.5% O_2	2,507
Heat Input to the Gasifier (HHV), Btu/hr x 10^6	3,195
Steam Turbine Output, MW	70.6
Gasification Plant Power Consumption, MW	(51.8)
ASU Power Consumption, MW	(35.4)
Net Power Consumption (Power Import), MW	(18.4)

Table 2

**Environmental Emissions Summary*
of the IGCC Coal to Hydrogen Plant**

Total CO_2 Vent Gas Emissions	
CO_2 Vent Gas Stack Exhaust Flow Rate, lb/hr	546,300
CO_2 Vent Gas Stack Exhaust Temperature, °F	50
Emissions	
SO×, ppmvd	0
SO× as SO_2, lb/hr	0
NO×, ppmvd	0
NO× as NO_2, lb/hr	0
CO, mole%	0.51
CO, lbl/hr	1,796
Incinerator and Steam Boiler Emissions	
Stack Exhaust Flow Rate, lb/hr	986,500
Stack Exhaust Temperature, °F	500
Emissions (at 3% oxygen, dry basis)	
SO×, ppmvd	84
SO× as SO_2, lb/hr	191
NO×, ppmvd	40
NO× as NO_2, lb/hr	27
CO, ppmvd	50
CO, lbl/hr	50
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	1,532,900
Emissions	
SO×, ppmvd	68
SO× as SO_2, lb/hr	191
NO×, ppmvd	13
NO× as NO_2, lb/hr	27
CO, mole%	0.15
CO, lbl/hr	1846
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	98.5

* Expected emissions performance

Table 3

Subtask 1.7 VIP and Optimization Items

Plant Section	Description
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Redesigned the gasifier for increased capacity • Used full slurry feed quench in the gasifier second stage • Used a cyclone and an advanced dry char filter system to remove particulates from the syngas • Improved the burner design
400	• Use of a Rectisol system for AGR and CO_2 removal • Simplified Claus plant, amine, and sour water stripper resulting in lower incinerator emissions • Higher CO conversion • Higher hydrogen recovery
General	• Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 4

Design and Daily Average Feed and Product Rates for the Subtask 1.7 IGCC Coal to Hydrogen Plant

		Daily Average	
Inputs	Design Rate	Availability	Rate
Coal, dry tpd	3,007	82.15%	2,470.2
Electric Power, MW	18.4	82.15%	15.1
River Water, gpm	2,457	82.15%	2,018
Products			
Hydrogen, MMscfd	142.1	81.33%	116.7
Sulfur, tpd	76.4	82.15%	62.8
Slag, tpd	474.3	82.15%	389.6
CO_2, tpd	7,125.0	81.33%	5,794.8

Table 5

Sensitivity of Individual Component Prices and Financial Parameters for the Subtask 1.7 Coal to Hydrogen Plant Starting from a 12% ROI

(with a Hydrogen Price of 2.790 $/Mscf)

	Decrease				Increase		
	ROI	Value	% Change	**Base Value**	% Change	Value	ROI
Products							
Hydrogen	7.41%	2.511 $/Mscf	-10%	**2.790 $/Mscf**	+10%	3.069 $/Mscf	16.32%
Slag	11.80%	-5 $/t	---	**0 $/t**	---	5 $/t	12.20%
Sulfur	11.98%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.02%
Feeds							
Coal	12.62%	19.8 $/t	-10%	**22.00**	10%	24.2 $/t	11.38%
Power	12.12%	24.3 $/MW-hr	-10%	**27.0 $/MW-hr**	+10%	29.7 $/MW-hr	11.88%
Financial							
EPC Cost	13.58%	503.3 MM$	-5%	**529.8 MM$**	+5%	556.3 MM$	10.55%
EPC Cost	15.29%	476.8 MM$	-10%	**529.8 mm$**	+10%	582.8 MM$	9.20%
Interest Rate	15.30%	8%	-20%	**10%**	+20%	12%	8.68%
Loan Amount	11.48%	72%	-20%	**80%**	+20%	88%	12.83%
Tax Rate	12.48%	36%	10%	**40%**	+10%	44%	11.48%

Figure 1

Simplified Block Flow Diagram for the Coal to Hydrogen Plant

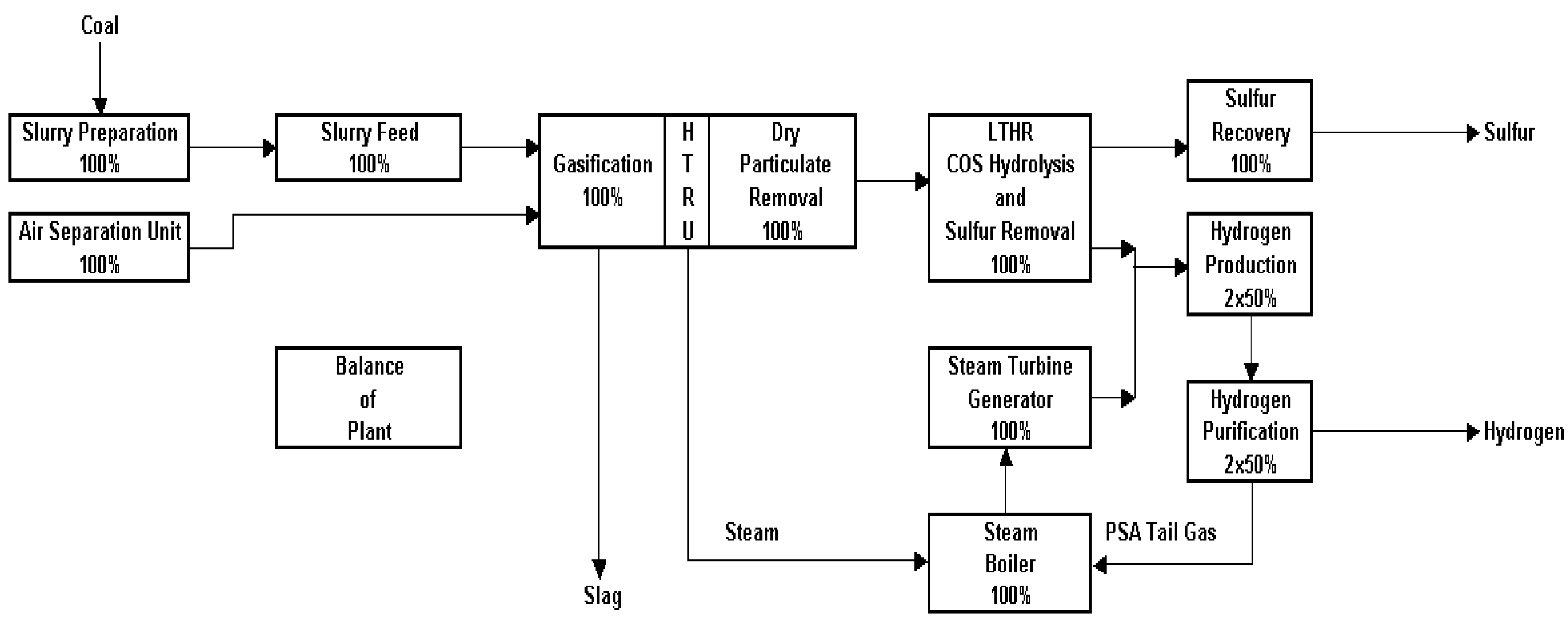


Figure 2

Effect of Hydrogen Selling Price on the Return on Investment

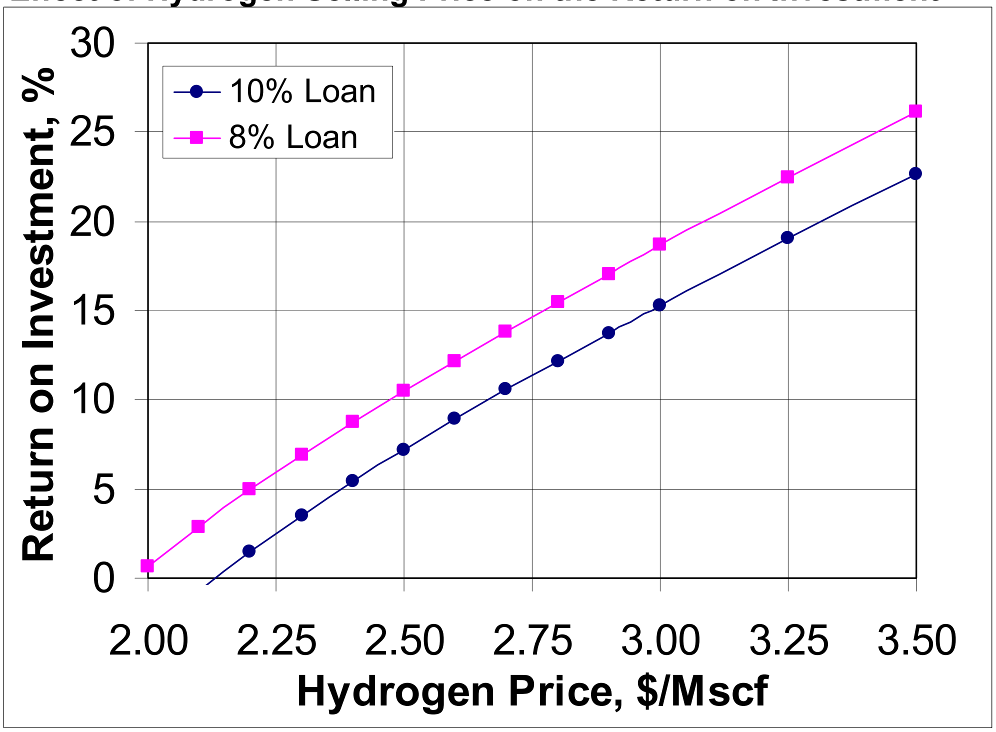


Figure 3

Effect of Hydrogen Selling Price on the Net Present Value at a 12% Discount Rate

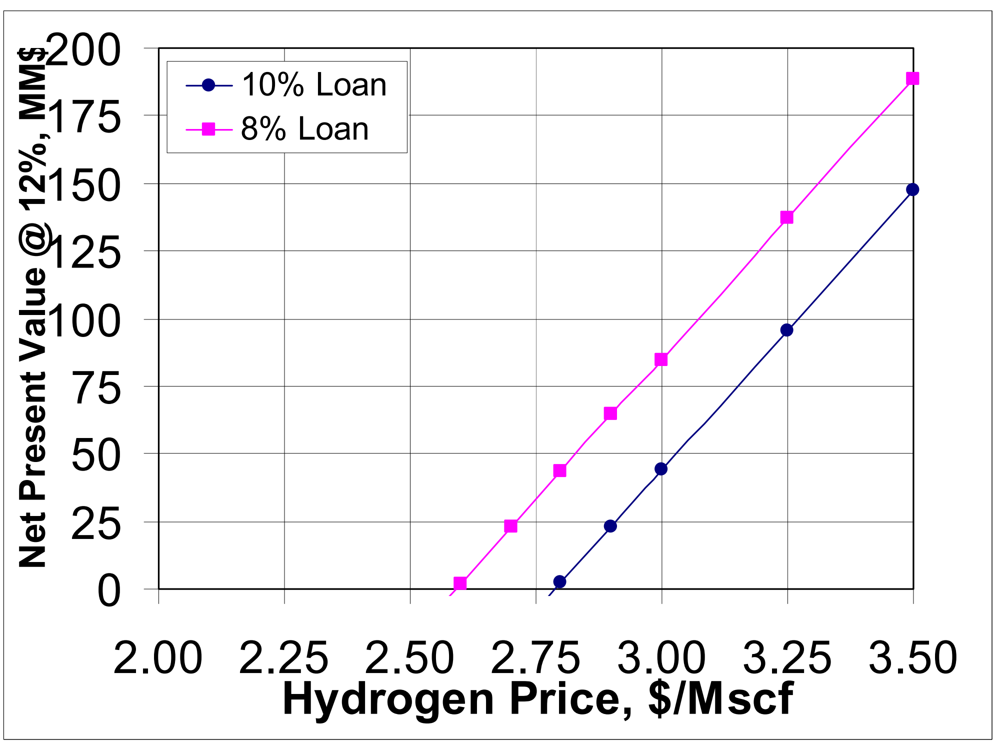


Figure 4

Effect of Hydrogen Availability on the Return on Investment with a Hydrogen Price of 2.79 $/Mscf and a 10% Loan Interest Rate

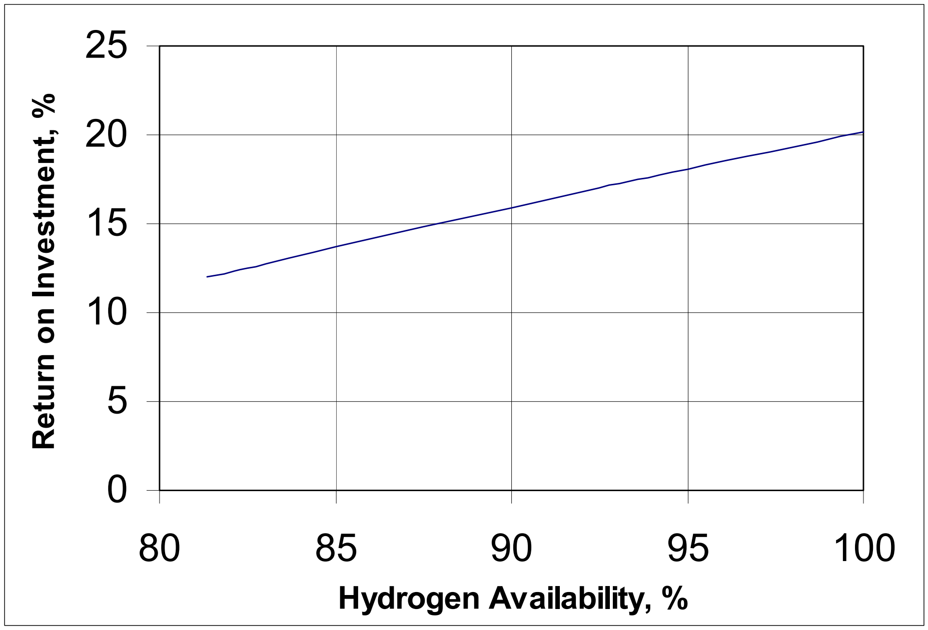


Figure 5

Effect of Hydrogen Availability on the Net Present Value at a 12% Discount Rate with a Hydrogen Price of 2.79 $/Mscf and a 10% Loan Interest Rate

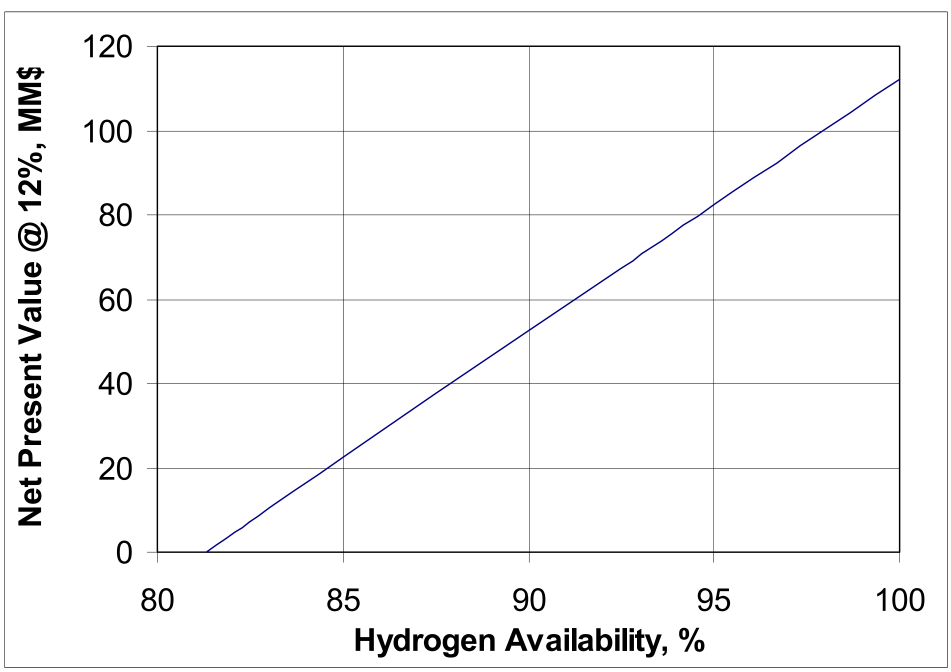


Figure 6

Effect of Hydrogen Availability on the Required Hydrogen Selling Price for a 12% Return on Investment

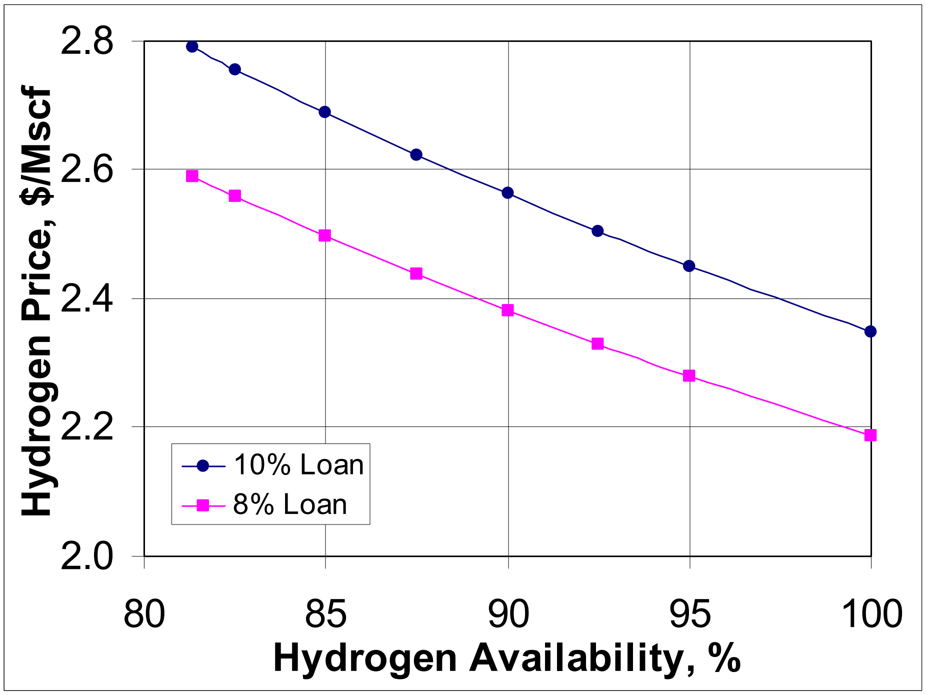
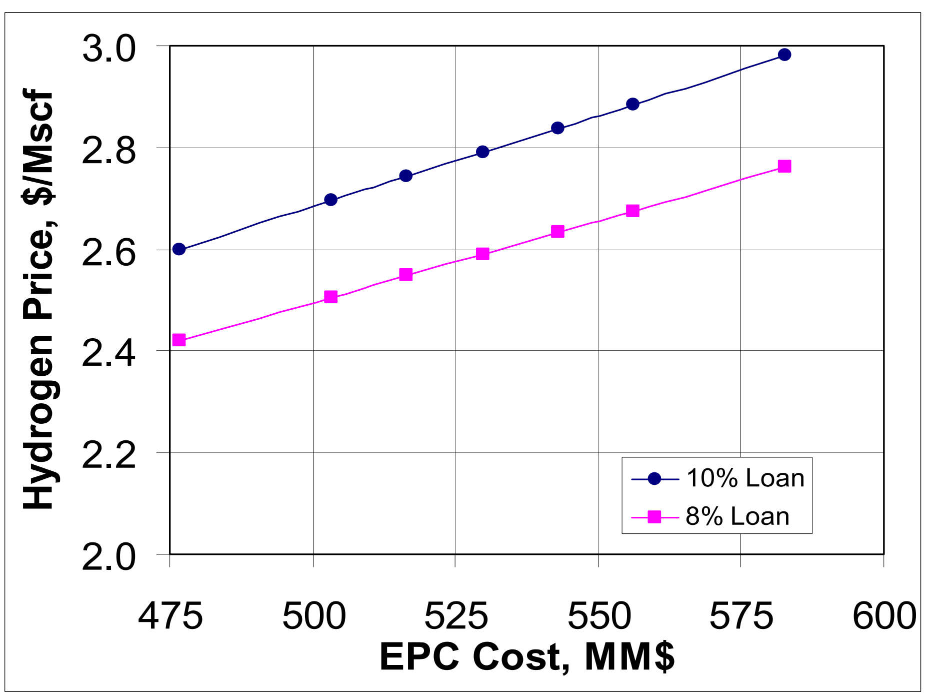


Figure 7

Effect of EPC Cost on the Required Hydrogen Selling Price for a 12% Return on Investment



Appendix H

Subtask 1.7 (Appendix A)

Coal to Hydrogen Plant

Subtask 1.7 (Appendix A)
Table of Contents

Figures

Appendix A

Subtask 1.7 – The Coal to Hydrogen Plant

A.1 Introduction

The objective of this project is to develop optimized engineering designs and costs for four Integrated Gasification Combined Cycle (IGCC) plant configurations. This work will develop optimized IGCC plant systems starting with commercial demonstration cost data and operational experience from the Wabash River Coal Gasification Repowering Project. The Wabash River Repowering Project consists of a nominal 2,500 TPD gasifier producing clean syngas for a GE 7FA gas turbine and steam for repowering an existing steam turbine.

Subtask 1.1 developed a design and current cost for the Wabash River Project Greenfield Plant. This plant is a coal fed IGCC power plant based on the Wabash River Repowering Project located at a generic greenfield site in the Midwest originally processing Illinois No. 6 coal. Subtask 1.2 developed a design and current cost for a Coal to Power IGCC plant producing electric power, hydrogen, steam, and fuel gas at a Gulf Coast location adjacent to a refinery

Subtask 1.3 optimized the Subtask 1.2 facility to develop an Optimized Petroleum Coke IGCC Coproduction Plant producing electric power, hydrogen and steam at a Gulf Coast location adjacent to a petroleum refinery. The plant design was optimized using both Global Energy's petroleum coke gasification experience and Bechtel's engineering and procurement tools, and Value Improving Practices (VIP) procedures.

Subtask 1.4 developed a design and installed capital cost for a future, highly optimized advanced design coal to power IGCC plant using an advanced gas turbine that is expected to be commercially available near the end of the decade. This plant incorporates the Value Improving Practices (VIP) results that were developed as part of Subtask 1.3 and several additional items specifically applicable to Subtask 1.4, to create an optimized facility for the production of power from coal.

Subtask 1.5 developed designs and cost estimates for two current single-train power plants based on the Subtask 1.3 Base Case design using General Electric 7FA+e combustion turbines. The objective of this study was to compare the performance, similarities, differences, and costs of two similar power projects with one being fueled by petroleum coke, and the other being fueled by coal.

Subtask 1.6 developed a design and cost estimate for a nominal 1,000 MW coal fueled power plant based on the subtask 1.3 Next Plant design using General Electric 7FA+e combustion turbines. This four-train plant has a design export power production of 1154.6 MW.

This appendix summarizes the results of Subtask 1.7. The objective of Subtask 1.7 is to develop a design and installed cost of a large IGCC coal to hydrogen plant based on an enlarged Subtask 1.3 gasifier. The plant produces 142 MMscfd of 99% hydrogen from

3,007 TPD of dry Illinois No. 6 coal. Hydrogen purification is accomplished by a two-stage Rectisol unit followed by PSA (pressure swing adsorption). The first-stage of the Rectisol unit removes the sulfur containing compounds from the syngas before shifting, and the second-stage removes most of the carbon dioxide from the shifted hydrogen. Final product purification is done by PSA.

In Subtasks 1.3 and 1.4, Bechtel and Global Energy implemented a project specific Value Improving Practices program to reduce the installed and operating costs associated with the plant to develop the design for the Optimized Coal to Power IGCC Plant. Those improvements which are applicable to this IGCC Hydrogen to Coal plant are included in this design. The VIP team included process design and construction specialists from Bechtel, gasification experts from Global Energy, and operating and maintenance personnel from the Wabash River Repowering Project. The team implemented Value Improving Practices covering the following areas to improve the plant performance and return on investment.

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Design-to-Capacity
- Traditional Value Engineering
- Process Availability (Reliability) Modeling
- Plant Layout Optimization
- Constructability Review / Schedule Optimization
- Operation and Maintenance and Savings

This appendix contains the following design and cost information:

- The design basis
- Block flow diagram
- Plant description
- Overall site plan of the coal to power IGCC plant
- Artist's view of the plant
- Overall material, energy and utility balance
- Plant performance summary
- Environmental emissions summary
- Major equipment list
- Project schedule
- Capital cost summary

The following sections describe the results of Subtask 1.7, the design and cost estimate for the Coal to Hydrogen Plant.

Section A2 contains the design basis for the Subtask 1.7 Coal to Hydrogen Plant. Section A3 contains descriptions of the various sections of the plant. Section A4 summarizes the overall plant performance. Section A5 contains a listing of the major pieces of equipment within the plant. Section A6 contains a construction schedule for the plant and a capital cost summary.

A.2 Design Basis

This section contains the design basis for the future Optimized Coal to Power IGCC Plant.

A.2.1 Capacity

The Coal Hydrogen Plant will process a nominal 3,000 TPD of Illinois No. 6 coal (dry basis) to produce syngas that will produce about 140 MMscfd of 99% hydrogen. Sulfur and slag are the only coproducts. The plant has an import power requirement of 18.4 MW.

A.2.2 Site Conditions

Location	Typical Mid-Western State
Elevation, ft	500
Air Temperature	
Maximum, °F	93
Annual, °F	59
Minimum, °F	-20
Summer Wet Bulb, °F	70
Relative Humidity, %	60
Barometric Pressure, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

A.2.3 Coal

Type	Illinois No. 6	
	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,295
Analysis, wt%		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

A.2.4 Water

Cations	mg/L	As equivalent ppm of CaCO3
Aluminum	0.006	0.033
Arsenic	0.002	
Barium	0.055	0.040
Boron	0.154	
Calcium	74.0	185
Chromium	0.005	
Copper	0.002	0.003
Iron	0.028	0.050
Lead	<0.001	0.000
Lithium	0.006	
Magnesium	26.0	107.1
Manganese	0.009	0.016
Molybdenum	0.008	
Potassium	4.8	6.1
Sodium	33.0	71.9
Selenium	<0.001	
Strontium	0.297	0.339
Vanadium	0.010	
Zinc	0.008	0.012
Total Cations		371

Anions	mg/L	As equivalent ppm of CaCO3
Carbonate		
Bicarbonate	245.0	200.9
Chloride	44.0	62.0
Sulfide	79.0	82.2
Nitrate - Nitrogen	4.88	4.0
Phosphorus	0.538	4.482
Fluoride	0.25	0.665
Chloride (add to balance)	12.0	16.9
Total Anions		371

Weak Ions	mg/L	As equivalent ppm of CaCO3
Ammonia Nitrogen	0.132	
Dissolved Silica	7.1	

Other Characteristics	mg/L	As equivalent ppm of CaCO3
Total Dissolved Solids (TDS)	419	
Standard Conductivity	671	
Total Alkalinity		201
Total Hardness		290
Total Organic Carbon	4 to 11.2	
Turbidity	8 to 100	
PH	7.6 to 8.4	
Total Nitrogen	6.1	
Total Suspended Solids	23 to 336	

A.2.5 Hydrogen Product

The product hydrogen will have a minimum purity of 99.0%, contain no more than 10 ppm by volume of CO, and be sulfur and CO_2 free. The impurities shall consist of argon, nitrogen and methane. The hydrogen shall be delivered at 1,000 psig.

A.2.6 Natural Gas

Natural gas will be available for startup. The natural gas will have a HHV of 1,000 Btu/scf and a LHV of 900 Btu/scf. No significant amounts of natural gas will be used during normal operations.

A.3 Plant Description

A.3.1 Block Flow Diagram

The Subtask 1.7 IGCC Coal to Hydrogen Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier/High Temperature Heat Recovery(HTHR)/Cyclone and Dry Char Filter Particulate Removal System
- Syngas Cleanup, Hydrogen Production and Recovery
    - Sulfur Removal by Rectisol
    - Hydrogen Production
    - Carbon Dioxide Removal by Rectisol
    - Hydrogen Purification by PSA
    - Sulfur Recovery
    - Steam Generation
- Air Separation Unit (ASU)
- Power Block
    - Steam Turbine Generator(STG)/Auxiliary Equipment
- Balance of Plant

Figure A1 is a simplified block flow diagram (BFD) of the above process blocks and subsystems. Multiple process trains and the relative capacity of each train are noted on the BFD.

A.3.2 General Description

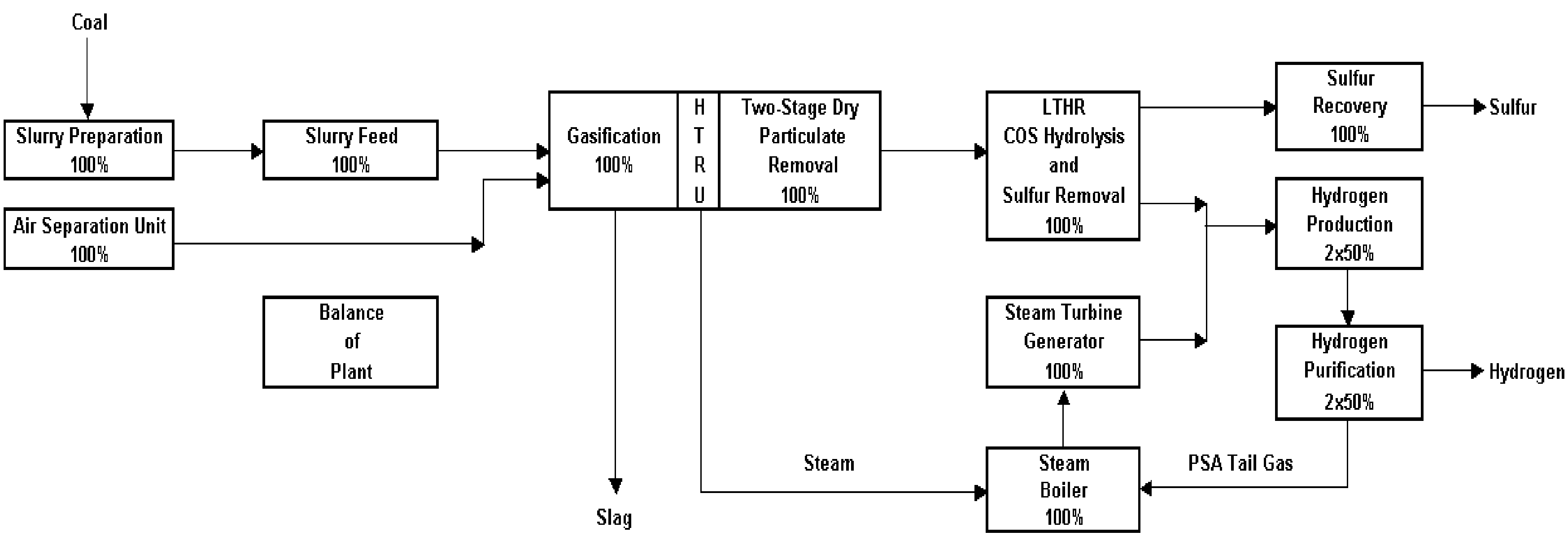
The plant is divided into the six distinct areas.

- Fuel Handling Unit
- Gasification Plant
- Hydrogen Production and Recovery
- Air Separation Unit
- Power Block
- Balance of Plant

Section A.3.3 describes the additional fuel handling facilities required for the coal from unloading to on-site storage and conveying to the gasification plant.

Figure A1

Simplified Block Flow Diagram for the Coal to Hydrogen Plant



Section A.3.4 describes the Global Energy gasification plant. This plant employs an oxygen-blown, two-stage entrained flow gasifier to convert the coal to syngas. The gasification plant includes several process units to remove impurities from the syngas. However, the dry char filtration system used at the Wabash River Repowering Project to remove particulates from the syngas has been replaced by a lower cost cyclone and dry char filter system.

Section A.3.5 describes the air separation unit (ASU), which employs a medium pressure cryogenic air separation process. A 99.5 % purity oxygen stream is produced as the oxidant for the gasifier.

Section A.3.6 describes the hydrogen production, purification and compression area, which consists of two parallel syngas CO shift units, a two-stage Rectisol unit, two parallel PSA hydrogen purification units, and three hydrogen compressors.

Section A.3.7 describes the steam turbine power production area.

Section A.3.8 describes the balance of plant (BOP). The BOP portion of the Optimized Coal to Power IGCC Plant includes water systems, air systems, relief and blowdown, interconnecting piping, electrical, instrumentation and controls, auxiliary fuel, civil structures, and effluent treatment systems.

A site plan and an artist's conception of the Optimized Coal to Power IGCC Plant are shown in Figures A2 and A3 at the end of Section A.3. The Comet plant layout model generated these figures.

A.3.3 AREA 100 – Fuel Handling

The coal handling system provides the means to receive, unload, store, reclaim, and convey coal to the storage facility. Coal is delivered to the site by rail and transferred to the gasification area through the coal unloading system to the crusher house. Coal also can be delivered by truck and dumped directly onto the coal pile when train deliveries are not available.

Coal is transferred from the crusher house to the active coal storage pile by transfer belt conveyors. Coal is reclaimed from the active coal storage pile to the gasification plant coal silo by variable rate feeder-breakers and the reclaim belt conveyors.

A.3.4 Gasification Process

The gasification plant consists of several subsystems including slurry preparation, gasification and high temperature heat recovery, slag handling, particulate removal and low temperature heat recovery, sour water treatment, acid gas removal, and sulfur recovery. Each of these subsystems is briefly discussed below.

A.3.4.1 AREA 150 – Slurry Preparation

Coal slurry feed for the gasification plant is produced by wet grinding in a rod mill. A conveyor delivers the coal into the rod mill feed hopper. Water is added in order to produce the desired slurry solids concentration. The slurry water includes water that is recycled from other areas of the gasification plant. Prepared slurry is stored in an agitated tank.

All tanks, drums and other areas of potential atmosphere exposure of the product slurry or recycled water are closed and vented into the tank vent collection system for control of vapor emissions.

The entire slurry preparation facility is paved and curbed to collect spills, leaks, wash down, and rain water. A trench system carries this water to a sump where it is pumped into the recycle water storage tank.

A.3.4.2 Gasification, High Temperature Heat Recovery, and Particulate Removal

Global Energy's E-GAS^{TM} Gasification process consists of two stages, a slagging first stage and an entrained flow non-slagging second stage. The slagging section, or first stage, is a refractory lined vessel into which oxygen and recycle char and unreacted coal are fired via two mixer nozzles. The coal slurry, recycle char and oxygen are fed sub-stoichiometrically at an elevated temperature and pressure to produce a high temperature syngas. The oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point; thereby ensuring good slag removal while producing high quality syngas.

The coal is almost totally gasified in this environment to form a synthetic fuel gas consisting primarily of hydrogen, carbon monoxide, carbon dioxide, and water. Sulfur in the coal is converted to primarily hydrogen sulfide (H_2S) with a small portion converted to carbonyl sulfide (COS); both of which are removed by downstream processing.

Mineral matter in the coal forms a molten slag which flows continuously through the tap hole into a water quench bath located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This continuous slag removal technique eliminates high-maintenance, problem-prone lock hoppers and completely prevents the escape of raw gasification products to the atmosphere during slag removal. This slag is then dewatered and removed from the process.

The raw synthesis gas generated in the first stage flows upward from the first stage into the second stage of the gasifier. The non-slagging second stage of the gasifier is a vertical refractory-lined vessel into which a portion of the coal slurry feed stream is injected via an atomizing nozzle to mix with the hot syngas stream exiting the first stage. This coal feed lowers the temperature of the gas exiting the first stage by the endothermic nature of the reactions, thereby generating more gas at a higher heating value. The syngas temperature is further reduced by evaporation of the water entering with the coal slurry. No oxygen is introduced into the second stage.

The gas and entrained particulate matter (char and unreacted coal) exiting the gasifier is further cooled in a firetube heat recovery boiler system where saturated steam at 1,650 psia is produced. Steam from this high temperature heat recovery system is super-heated in the gas turbine heat recovery system for use in power generation.

To remove solids from the syngas, the raw gas passes through a two-step particulate removal system consisting of a cyclone located upstream of the high temperature heat recovery unit and a dry char filter system located downstream. The recovered char and unreacted coal particles are recycled to the gasifier.

A.3.4.3 AREA 350 – Slag Handling

The slag slurry leaving the slag crushers on the outlet of the quench section of the gasifier flows continuously through the pressure let down system and into a dewatering bin. The bulk of the slag settles out in the bin while water overflows a weir at the top of the bin and goes to a settler where the remaining solids are collected. The clear water gravity flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. Dewatered slag is loaded into a truck or rail car for transport to market or to storage. The fines slurry from the bottom of the settler is recycled to the slurry preparation area.

The dewatering system contains dewatering bins, a water tank, and water circulation pumps. All tanks, bins, and drums are vented to the tank vent collection system.

A.3.5 AREA 200 – Air Separation Unit (ASU)

The ASU consists of several subsystems and major pieces of equipment, including an air compressor, air cooling system, air purification system, cold box, and product handling and backup systems.

Gaseous oxygen leaves the cold boxes at moderate pressure and is then compressed in centrifugal compressors and delivered to the gasifiers.

Nitrogen tanks with steam vaporizers provide gaseous nitrogen. These tanks also serve as transfer and buffer vessels for normal gaseous nitrogen production.

A.3.6 Area 400 – Sulfur Removal, Sulfur Recovery, and Hydrogen Production

A.3.6.1 Low Temperature Heat Recovery

Filter syngas is scrubbed to remove water-soluble contaminants such as chlorides. The scrubbed syngas is cooled and sent to the first stage of the Rectisol unit for H_2S and COS removal (the acid gas removal section). This cooling condenses water, ammonia, some carbon dioxide and hydrogen sulfide in an aqueous solution, which is collected and sent to the sour water treatment unit. Some of the cooled syngas goes to the syngas recycle compressor for use in various areas of the plant. This gas is used for quenching in the second stage of the gasifier and back pulsing the barrier filters.

A.3.6.2 Sour Water Treatment System

Water condensed during cooling of the sour syngas contains small amounts of dissolved gases; i.e., carbon dioxide, hydrogen sulfide, ammonia, and trace contaminants. This condensed water and any other process water is treated in the sour water treatment system of Area 400.

The gases are stripped out of the sour water in a two-step process. First the acid gases are removed in the acid gas stripper column by steam stripping. The stripped gases are directed to the Sulfur Recovery Unit (SRU). The water exits the bottom of the acid gas stripper column, is cooled, and a major portion is recycled to slurry preparation. The remaining water is treated in the ammonia stripper column to remove the ammonia, filtered to remove trace organics and solids, and then directed to the waste water management system. The stripped ammonia is combined with the recycled slurry water. Water recycled to the slurry preparation area is cooled in an exchanger using cooling tower water.

The filtered water is sent to the clean water collection for final treatment, if necessary, before discharge.

The sour water treatment system is a single train with backup sour water feed storage.

A.3.6.3 AREA 410 Rectisol Acid Gas Removal (AGR) and CO_2 Removal

First-Stage

Hydrogen sulfide in the sour syngas is removed in an absorber column at high pressure and low temperature in the first-stage of a Rectisol unit using a methanol solvent. After hydrogen sulfide removal, the syngas is moisturized and heated before going to the CO shift reactors.

The hydrogen sulfide rich methanol solution exits the absorber and flows to two stripper columns where the hydrogen sulfide is removed by lowering the pressure and stripping.

The concentrated H_2S exits the top of the stripper column and flows to the sulfur recovery unit. The lean methanol exits the bottom of the stripper, is cooled, and then recycled to the absorber.

Second-Stage

After leaving the CO shift reactors, the shifted syngas is returned to the Rectisol unit where it is cooled before entering a separate refrigerated adsorption column for CO_2 removal. This column removes about 89% of the CO_2 reducing the CO_2 concentration in the scrubbed hydrogen stream to less that 12%.

The CO_2 is removed from the from the methanol at lower pressure by stripping and sent to the first-stage desulfurization column.

A.3.6.4 AREA 420 - Sulfur Recovery Unit (SRU)

The concentrated hydrogen sulfide from the AGR unit and the CO_2 and H_2S stripped from the sour water are fed to a reaction furnace, a waste heat recovery boiler, and then to a series of Claus catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur from the SRU is recovered as a molten liquid and sold as a by-product.

The tail gas stream, composed of mostly carbon dioxide and nitrogen with trace amounts of sulfur dioxide, exits the last catalytic stage and is directed to tail gas recycling.

The tail gas is hydrogenated to convert all the sulfur species to H_2S, cooled to condense the bulk of the water, compressed, and then injected into the gasifier. This allows for very high sulfur removal efficiency with low recycle rates.

A.3.6.5 AREA 450 – CO Shift, PSA and Hydrogen Compression

A.3.6.5.1 AREA 450 – CO Shift Unit

Hydrogen production by the CO shift reaction is highly exothermic. High temperatures favor fast reaction rates, but result in unfavorable equilibrium conditions. Conversely, low temperatures favor the equilibrium conditions that allow the shift reaction to go to completion and result in low CO levels in the product gas. Also, the maximum allowable reactor outlet temperature must be below the catalyst sintering point and within the limits for practical vessel design. Thus, a three-stage reaction system is used with interstage cooling. The first and second reactors are high temperature shift reactors which are designed to achieve high reaction rates at the highest allowable outlet temperature, and the third is designed to give a high conversion at a lower outlet temperature where the equilibrium conditions are more favorable. Approximately 99.1 percent of the carbon monoxide is converted to hydrogen in the shift reactors.

The clean syngas from the syngas moisturizer and preheater goes to the first CO shift reactor. Medium pressure steam is preheated and mixed with the syngas before it goes to the first-stage high temperature shift reactor. Adjusting the rate of steam addition controls the first-stage reactor outlet temperature. The CO conversion is 79.7% in the first reactor.

The hot gas leaving the first high temperature shift reactor is cooled by preheating the clean syngas and steam going to the first reactor. It is further cooled by feedwater heating before entering the second high temperature shift reactor where the CO conversion is 12.8% based on the amount of CO entering the first reactor.

The hot gas leaving the second high temperature shift reactor is cooled by steam generation producing medium pressure (420 psig) steam before going to the low temperature shift reactor. The shifted syngas leaving the third(low temperature) reactor is cooled by heating water for the syngas moisturizer, by preheating condensate, and then by a trim water cooler before going to the Rectisol unit for CO_2 removal. Process condensate is separated in the knock-out drum and sent to condensate treatment.

Two 50% trains are needed as limited by maximum reactor vessel diameter to provide the required capacity and system reliability.

A.3.6.5.2 AREA 460 - Pressure Swing Adsorption Unit (PSA)

The shifted gas after CO_2 removal in the Rectisol unit is sent to the pressure swing adsorbers for purification of the hydrogen product. The PSA system is based on the principle of pressure reduction and rapid cycle operation to remove impurities from the adsorbent. It consists of three major parts, i.e., adsorber vessels filled with adsorbent, a prefabricated valve skid, and a control panel containing the cycle control system.

A complete PSA cycle consists of four basic steps: adsorption, depressurization, purge at low pressure, and repressurization. Multiple adsorbent beds are used for high throughputs and hydrogen recovery.

Approximately 142 MMscfd of 99% hydrogen is produced and sent to the hydrogen compressors. The hydrogen product is 99% pure with no more than 10 ppmv of CO. It is sulfur and CO_2 free. Argon, nitrogen and methane are the impurities. The sweep (tail) gas from the PSA is sent to the incinerator to produce high pressure steam for power generation.

There are two parallel PSA units.

A.3.6.5.3 AREA 470 - Hydrogen Compression

The hydrogen from the PSA unit is compressed to 1000 psig by two hydrogen compressors for sale. A spare hydrogen compressor is provided for reliability.

A.3.7 Power Block

The power block consists only of a steam turbine generator (STG), and numerous supporting facilities.

A.3.7.1 AREA 600 - Steam Turbine (ST)

Medium and low pressure steam are extracted from the steam turbine for use elsewhere within the plant. Turbine exhaust steam is condensed in a surface condenser. The steam turbine produces about 71 MW of electric power for internal use within the plant.

A.3.7.2 Power Delivery System

The power delivery system includes the steam turbine generator output at 13.8 kilovolts (kV) connected through a generator breaker to the associated main power step-up transformer. The HV switch yard receives the energy from the generator step-up transformer at 230 kV.

An emergency shutdown transformer is included which connects the 230 kV switch yard with essential safe shutdown loads.

A.3.7.3 Cooling Water System

Two cooling water systems provide the cooling duty for the plant, one for the power block and the other for the air separation unit and gasification facility. The major components of the cooling water system consist of two cooling towers and circulating water pumps. All plant cooling requirements are provided via underground piping and piping in the pipe rack. The cooling towers are multi-cell mechanically induced draft towers, sized to provide the design heat rejection at the ambient conditions corresponding to the maximum summer temperature. Cooling tower blowdown discharges to the wastewater management system.

Chemical treatment systems, including metering pumps, storage tanks and unloading facilities provide the necessary biocide, pH treatment and corrosion inhibiting chemicals for the circulating water system.

A.3.8 AREA 900 - Balance of Plant

A.3.8.1 Fresh Water Supply

Industrial river water is filtered for use as the fresh makeup water supply. A demineralizer is provided to supply demineralized water for boiler water makeup. The demineralizer regeneration wastewater is sent to a process waste collection tank, where it is neutralized before discharge.

A.3.8.2 Fire and Service Water System

The fire water system includes a loop around the principal facilities with fire hydrants located for easy access. The system loops around the gasification and oxygen unit areas, the power block, and the switchyard.

Filtered fresh water is used to fill an onsite water storage tank and supply to the system. A jockey pump is used to maintain line pressure in the loop during stand-by periods. During periods of high water usage, a motor driven fire pump will be used. A diesel driven fire pump will be used in case of power loss.

A.3.8.3 Waste Water Management System

Clear wastewater includes water treatment effluent, cooling water blowdown, flushes and purges from equipment maintenance, filtered water from the ammonia stripper column (in Area 400), clarifier overflow, and sewage treatment overflow. These effluent streams are collected in the clean water collection pond.

Storm water is collected in a storm-water pond before going to the clean water collection pond. The water in the clean water collection pond is analyzed and treated, as required, until it meets permitted outfall specifications for discharge through the waste water outfall system.

A.3.8.4 Service and Instrument Air System

A compressed air system is provided to supply service and instrument air to users throughout the plant. The system consists of air compressors, air receivers, hose stations, and piping distribution for each unit. Additionally, the instrument air system consists of air dryers and a piping distribution system.

A.3.8.5 Incineration System

The tank vent stream is composed of primarily sweep gas and air purged through various in-process storage tanks that may contain small amounts of other gases such as ammonia and acid gas. The high temperature produced in the incinerator thermally destroys any hydrogen sulfide remaining in the stream before the gas is vented to the atmosphere. The incinerator exhaust feeds into a heat recovery boiler to produce process steam.

A.3.8.6 Flare

The process design provides for diverting syngas from the gas turbine to a flare. This would occur during gasification plant startup, shutdown and during short term upset periods when the turbine is unable to accept the syngas. The flare includes a natural gas fired pilot flame to ensure that the flare is continually operating.

A.3.8.7 Instrumentation and Control

Data acquisition, monitoring, alarming and control of the IGCC plant are implemented using a digital Distributed Control System (DCS). The DCS is the control system integrator of the various control components used throughout the plant, and allows the plant to be operated from the central control room (CCR) using the DCS as the control platforms. Accordingly, using either hardwired I/O, serial interface hardware, or fiber optics; the DCS interfaces with all plant equipment to provide the CCR operator the necessary plant-wide supervisory control, feedback, status and alarm information.

The gas and steam turbines, ASU, and the coal handling programmable logic controllers (PLC) will continue to execute all permissive, protective, and sequence control related to their respective equipment. They will be controlled either locally using the turbine vendor CRT/PLC man machine interface (MMI), or from the DCS using hardwired outputs and feedback inputs of selected critical steam turbine, generator, and ASU control parameters.

A.3.8.8 Buildings

The plant has a central building housing the main control room, office, training, other administration areas and a warehouse/maintenance area. Other buildings are provided for water treatment equipment, coal handling, slurry preparation, and the MCCs. The buildings, are heated and air-conditioned to provide a climate controlled area for personnel and electrical control equipment, as appropriate.

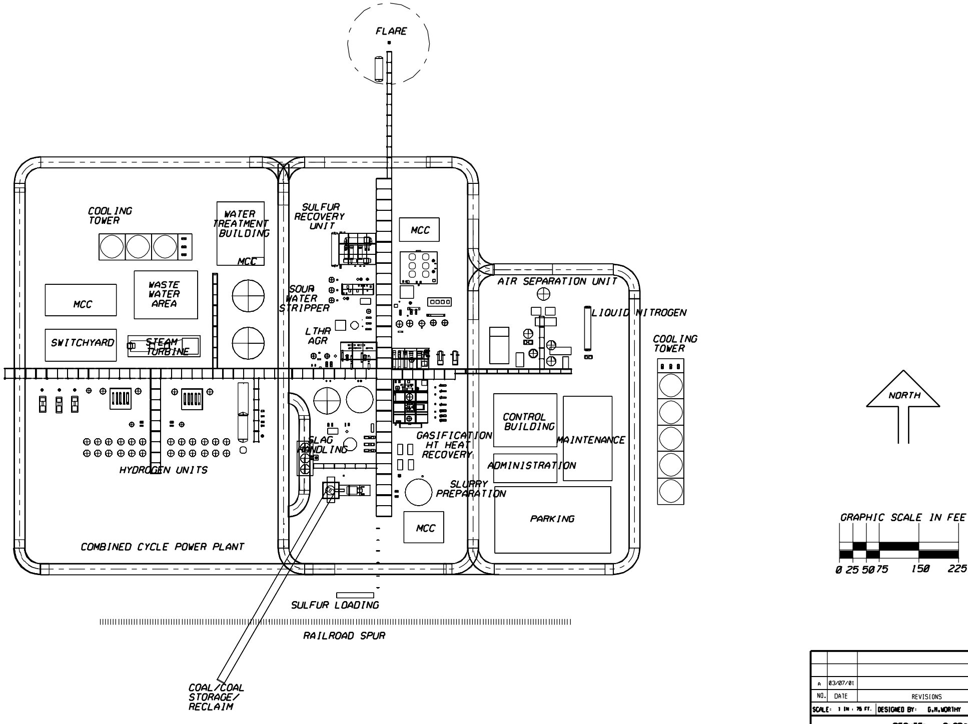
A.3.8.9 Safety Shower System

A series of strategically placed safety showers are located throughout the facility.

Figure A2

Site Plan of the

Coal to Hydrogen Plant



NO.	DATE	REVISIONS	BY	CHK	SUPV	PEM	CLIENT
A	03/07/01		GMW				

SCALE: 1 IN : 75 FT. DESIGNED BY: G.M.WORTHY DRAWN BY: G.M.WORTHY

BECHTEL - GLOBAL ENERGY
US DEPARTMENT OF ENERGY
GASIFICATION PLANT COST AND PERFORMANCE OPTIMIZATION

COAL TO H2 PLANT
SUBTASK 1.7

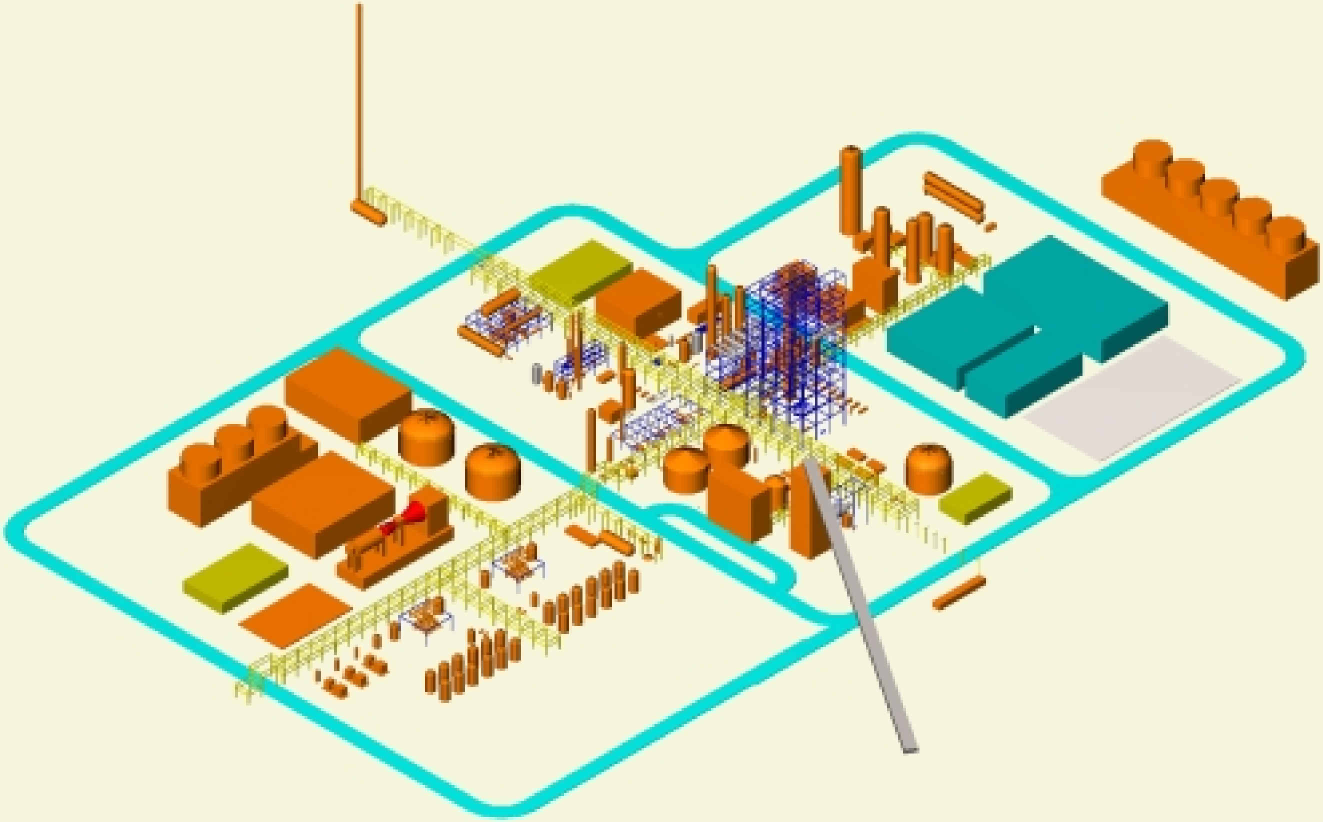
SITE PLAN

JOB NO:	DRAWING NO:	REV.
24355-104	SK - 00017	A

Figure A3

Artist's Conception of the

Coal to Hydrogen Plant



A.4 Plant Performance

A.4.1 Overall Material and Utility Balance

A detailed block flow diagram of the plant is shown in Figure A4, Coal to Hydrogen Plant Block Flow Diagram. Flow rates are shown for the major input and output streams and for the internal syngas streams.

As shown in the figure, the plant consumes 3,007 t/d of dry coal and produces 142 MMscfd of 99% hydrogen, 75.1 t/d of sulfur, and 474.4 t/d of slag (containing 15 wt% water). It consumes 2,457 gpm of river water. It also imports 18.4 MW of electric power.

Figure A5 shows the overall water flow diagram for the plant. This figure provides details of the water usage and losses within the plant. The waste water discharge is about 676 gpm which includes an allowance of 150 gpm for rain water.

A.4.2 Performance Summary

Table A1 summarizes the overall performance of the Optimized Coal to Power IGCC Plant. As shown in the table, the oxygen input to the gasifiers is 2,522 t/d of 99.5% oxygen, and the heat input is 3,195 MMBtu/hr HHV. The steam turbine produces 70.6 MW of power. Internal power usage consumes 89 MW requiring a net power import of 18.4 MW.

Table A2 summarizes the expected emissions from the IGCC Coal to Hydrogen Plant. The CO2 vent gas stack has an exhaust flow rate of 546,300 lb/hr at 50^{o}F. The incinerator and steam boiler stack has an exhaust flow rate of 986,500 lb/hr at 500^{o}F. On a dry basis adjusted to 3% oxygen, these gases have a SOx concentration of 84 ppmv, a NOx concentration of 40 ppmv, and a CO concentration of 50 ppmv.

The plant emits 1,532,900 lbs/hr of total exhaust gases having an average SOx concentration of 68 ppmv, an average NOx concentration of 13 ppmv, and an average CO concentration of 0.15 wt%. The sulfur removal is 98.5%.

[1] GT Pro is a registered trademark of the Thermoflow Corporation.

Table A1

Performance Summary of the IGCC Coal to Hydrogen Plant

Ambient Temperature, °F	59
Coal Feed, as received, TPD	3,517
Dry Coal Feed to Gasifiers, TPD	3,007
Total Fresh Water Consumption, gpm	2,457
Hydrogen, 99.0%, MMscfd	142.1
Sulfur, TPD	76.4
Slag Produced, TPD (15% moisture)	474.3
Total Oxygen Feed to the Gasifier, TPD of 99.5% O_2	2,507
Heat Input to the Hydrogen Plant (HHV), Btu/hr x 10^6	3,195
Cold Gas Efficiency to Clean Syngas (HHV), %	76.5
Steam Turbine Output, MW	70.6
Gasification Plant Power Consumption, MW	(51.8)
ASU Power Consumption, MW	(35.4)
Net Power Consumption (Power Import), MW	(18.4)

Table A2

Environmental Emissions Summary* of the IGCC Coal to Hydrogen Plant

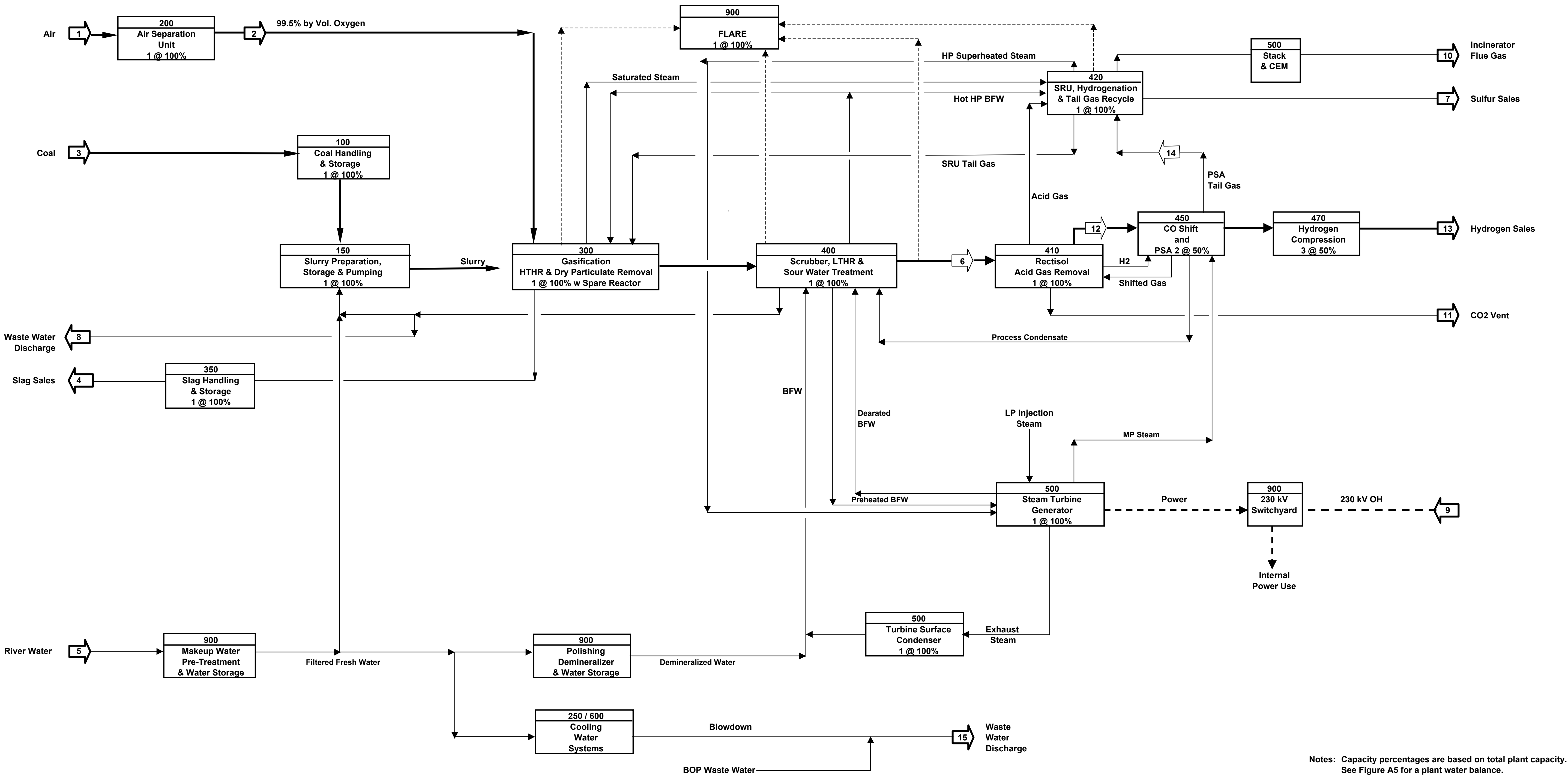
Total CO_2 Vent Gas Emissions	
CO_2 Vent Gas Stack Exhaust Flow Rate, lb/hr	546,300
CO_2 Vent Gas Stack Exhaust Temperature, °F	50
Emissions	
SO×, ppmvd	0
SO× as SO_2, lb/hr	0
NO×, ppmvd	0
NO× as NO_2, lb/hr	0
CO, mole%	0.51
CO, lbl/hr	1,796
Incinerator and Steam Boiler Emissions	
Stack Exhaust Flow Rate, lb/hr	986,500
Stack Exhaust Temperature, °F	500
Emissions (at 3% oxygen, dry basis)	
SO×, ppmvd	84
SO× as SO_2, lb/hr	191
NO×, ppmvd	40
NO× as NO_2, lb/hr	27
CO, ppmvd	50
CO, lbl/hr	50
Total Plant Emissions	
Exhaust Flow Rate, lb/hr	1,532,900
Emissions	
SO×, ppmvd	68
SO× as SO_2, lb/hr	191
NO×, ppmvd	13
NO× as NO_2, lb/hr	27
CO, mole%	0.15
CO, lbl/hr	1,846
VOC and Particulates, lb/hr	NIL
Opacity	0
Sulfur Removal, %	98.5

* Expected emissions performance

Figure A4

Detailed Block Flow Diagram of the

Coal to Hydrogen Plant



Notes: Capacity percentages are based on total plant capacity.
See Figure A5 for a plant water balance.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
	Air	Oxygen	Coal	Slag	Water	Syngas	Sulfur	Water	Power	Flue Gas	CO2	Syngas	Hydrogen	Tail Gas	Water						
Flow	11,590	2,522	3,007	474.3	1,229,000	548,767	76.4	31,215	18,400	986,470	593,752	807,875	142	22,981	307,000						
	Tons/Day	Tons/Day	Tons/Day	Tons/Day	Lb/Hr	Lb/Hr	Tons/Day	Lb/Hr	kWe	Lb/Hr	Lb/Hr	Lb/Hr	MMSCFD	Lb/Hr	Lb/Hr						
Nominal Pressure - psig	Atmos.	649	NA	NA	50	400	NA	62	NA	Atmos.	Atmos.	375	1,000	5	Atmos.						
Temperature - F	70	240	Ambient	193	70	81	333	80	NA	500	50	509	120	53	71						
HHV Btu/lb	NA	NA	12,749	NA	NA	4,999	NA	NA	NA	NA	0	3,026	57,832	23,151	NA						
LHV Btu/lb	NA	NA	12,275	NA	NA	4,653	NA	NA	NA	NA	0	2,817	48,893	21,724	NA						
Energy - MM HHV/hr	NA	NA	3,195	NA	NA	2,743	NA	NA	NA	NA	0	2,445	1,909	532	NA						
Energy - MM LHV/hr	NA	NA	3,076	NA	NA	2,553	NA	NA	NA	NA	0	2,276	1,614	499	NA						
Notes	Dry Basis	2,507 O2	Dry Basis	15%Wtr.	2,458 GPM		Sales	62 GPM	230 kV			For H2	99.6% H2		614 GPM						

DOE Gasification Plant Cost and Performance Optimization

Figure A4

Subtask 1.7

COAL TO HYDROGEN PLANT

BLOCK FLOW DIAGRAM

File: Fig A4 1.7 R1.xls February 21, 2002

Figure A5

Overall Water Flow Diagram of the

Coal to Hydrogen Plant

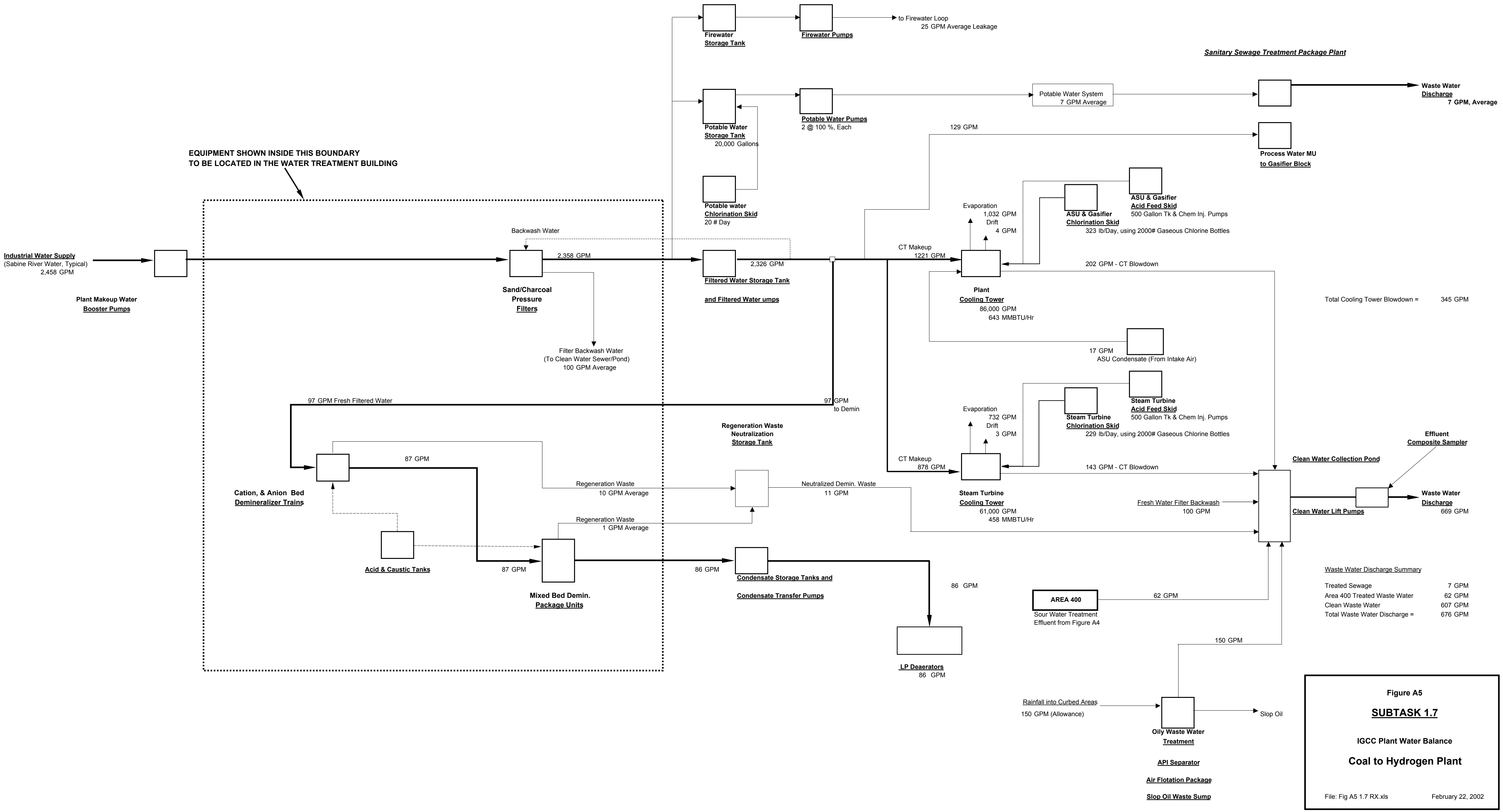


Figure A5

SUBTASK 1.7

IGCC Plant Water Balance

Coal to Hydrogen Plant

File: Fig A5 1.7 RX.xls February 22, 2002

A.5 Major Equipment List

Table A3 lists the major pieces of equipment and systems by process area in the IGCC Coal to Hydrogen Plant. Detailed equipment lists for systems that would be purchased as complete units from a single vendor, such as the Air Separation Unit, are not available.

Table A3

Equipment List for the Subtask 1.7 Coal to Hydrogen Plant

Fuel Handling – 100
Unit Train Rail Loop
Rotary Coal Car Dumper
Rotary Car Dumper Coal Pit
Rotary Dumper Vibratory Feeders
Rotary Dumper Building & Coal Handling Control Control/Electrical Rooms
Rotary Car Dumper Dust Collector
Rotary Car Dumper Sump Pumps
Coal Car Unloading Conveyor
Coal Crusher
Reclaim Coal Grizzly
Reclaim Conveyors
Storage/Feed Bins
Reclaim Pit Sump Pumps
Coal Dust Suppression System
Coal Handling Electrical Equipment and Distribution
Electric Hoist
Metal Detector
Magnetic Separator
Slurry Preparation – 150
Weigh Belt Feeder
Rod Charger
Rod Mill
Rod Mill Product Tank
Rod Mill Product Tank Agitator
Rod Mill Product Pumps
Recycle Water Storage Tank
Recycle Water Pumps
Slurry Storage Tank
Slurry Storage Tank Agitator
Slurry Recirculation Pumps
Solids Recycle Tank
Solids Recycle Tank Agitator
Solids Recycle Pumps
Rod Mill Lube Oil Pumps
Slurry Feed Pumps (1st Stage)
Slurry Feed Pumps (2nd Stage)

Table A3 (Continued)

Equipment List for the Subtask 1.7 Coal to Hydrogen Plant

ASU – 200
Air Separation Unit including:
Main Air Compressor
Air Scrubber
Oxygen Compressor
Cold Box (Main Exchanger)
Oxygen Compressor Expander
Liquid Nitrogen Storage
ASU, ST & Gasifier Area Cooling Water - 250
Cooling Water Circ Pump
Cooling Tower – ASU / Gasification (S/C)
Cooling Tower – Power Block (S/C)
Gasification - 300
Main Slurry Mixers
Second Stage Mixer
Gasifier
Post Reactor Residence Vessel
High Temperature Heat Recovery Unit
Cyclone Separator
Slag Pre-Crushers
Slag Crushers
Reactor Nozzle Cooling Pumps
Crusher Seal Water Pumps
Syngas Desuperheater
Nitrogen Heater
Pressure Reduction Units
Dry Char Filters
Syngas Scrubber
Syngas Recycle Compressor
Syngas Recycle Compressor K.O. Drum
Slag Handling – 350
Slag Dewatering Bins
Slag Settler
Slag Water Tank
Slag Water Pumps
Settler Bottoms Pumps
Slag Recycle Water Tank
Slag Feedwater Quench Pumps
Slag Water Recirc Pumps
Polymer Pumps
Slag Recycle Water Cooler

Table A3 (Continued)

Equipment List for the Subtask 1.7 Coal to Hydrogen Plant

LTHR/AGR – 400
Syngas Cooler
Syngas Water Scrubber
Sour Gas BFW Condenser
Sour Gas Condensate Condenser
Sour Gas CTW Condenser
Sour Water Level Control Drum
Sour Water Receiver
Sour Gas K.O. Drum
Sour Water Carbon Filter
RECTISOL SYSTEM Desulfurization Section CO2 Removal Section
Condensate Degassing Column
Degassing Column Bottoms Cooler
Sour Water Transfer Pumps
Ammonia Stripper
Ammonia Stripper Bottoms Cooler
Stripped Water Transfer Pumps
Quench Column
Quench Column Bottoms Cooler
Stripped Water Transfer Pumps
Degassing Column Reboiler
Ammonia Stripper Reboiler
Syngas Heater
Syngas Moisturizer
Moisturizer Recirc Pumps
Sulfur Recovery – 420
Reaction Furnace/Waste Heat Boiler
Condensate Flash Drum
Sulfur Storage Tank
Storage Tank Heaters
Sulfur Pump
Claus First Stage Reactor
Claus First Stage Heater
Claus First Stage Condenser
Claus Second Stage Reactor
Claus Second Stage Heater
Claus Second Stage Condenser
Condensate Level Drum
Hydrogenation Gas Heater
Hydrogenation Reactor
Quench Column
Quench Column Pumps
Quench Column Cooler

Table A3 (Continued)

Equipment List for the Subtask 1.7 Coal to Hydrogen Plant

Quench Strainer
Quench Filter
Tail Gas Recycle Compressor
Tail Gas Recycle Compressor Intercooler
Tank Vent Blower
Tank Vent Combustion Air Blower
Tank Vent Incinerator/Waste Heat Boiler
Tank Vent Incinerator Stack
CO Shift – 450
KO Drum
Gas-gas Exchanger
HT Shift Reactor #1
Gas-Water Exchanger #1
HT Shift Reactor #2
Gas-Water Exchanger #2
LT Shift Reactor
Gas-Water Exchanger #3
Gas-Water Exchanger #4
Gas-Water Exchanger #5
Gas-Water Exchanger #6
Trim Cooler
Start-up Fire Heater
ZnO Reactor
PSA Units – 460
PSA Units
H2 Compression – 470
Hydrogen Compressors
H2 Compressor Intercooler
Compressor Surge Drums
Stg. & Aux. - 600
Steam Turbine Generator (STG), Reheat, TC2F, complete with lube oil console
Steam Surface Condenser, 316L tubes
Condensate (hotwell) pumps
Power Block Aux. Power XformerS
Balance Of Plant - 900
High Voltage Electrical Switch Yard (S/C)
Common Onsite Electrical and I/C Distribution
DCS
In-Plant Communication System
15KV, 5KV and 600V Switchgear
BOP Electrical Devices
Power Transformers
Motor Control Centers
River Water - Makeup Water Intake and Plant Supply Pipeline
Pumphouse
Makeup Pumps (2 @250 HP)

Table A3 (Continued)

Equipment List for the Subtask 1.7 Coal to Hydrogen Plant

Makeup Water Pumps
Water Softner Skids
Carbon Filters
Cation Demin Skids
Degasifiers
Anion Demin. Skids
Demin. Polishing Bed Skids
Bulk Acid Tank
Acid Transfer Pumps
Demin- Acid Day Tank Skid
Bulk Caustic Tank Skid
Caustic Transfer Pumps
Demin- Caustic Day Tank Skid
Firewater Pump Skids
Waste Water Collection and Treatment
Oily Waste - API Separator
Oily Waste - Dissolved Air Flotation
Oily Waste Storage Tank
Sanitary Sewage Treatment Plant
Wastewater Storage Tanks
Waste Water Outfall
Monitoring Equipment
Common Mechanical Systems
Shop Fabricated Tanks
Miscellaneous Horizontal Pumps
Auxiliary Boiler
Safety Shower System
Flare
Flare K.O. Drum
Flare K.O. Drum Pumps
Chemical Feed Pumps
Chemical Storage Tanks
Chemical Storage Equipment
Lab Equipment

A.6 Project Schedule and Cost

A.6.1 Project Schedule

The schedule is based on the Wabash River Repowering project expanded for the Subtask 1.7 scope, with the start date commencing on notice to proceed and stopping at commercial operation. The total duration is 40 months which includes three months of performance testing before full commercial operation. Notice to proceed is based on a confirmed Mid-West plant site and the availability of basic process information, including process flow diagrams, heat and material balances, a preliminary issue of P&IDs, and performance specifications for major pieces of equipment such as the combustion and steam turbines, heat recovery steam generator, gasification reactor, and air separation unit.

The project construction schedule of the Coal to Hydrogen Plant was developed by examining that of the Wabash River Repowering Project and correcting for several problems that were encountered during construction. Furthermore, construction experts were included in the Value Improving Practices team that developed the plant layout so that both ease of construction and maintenance were considered.

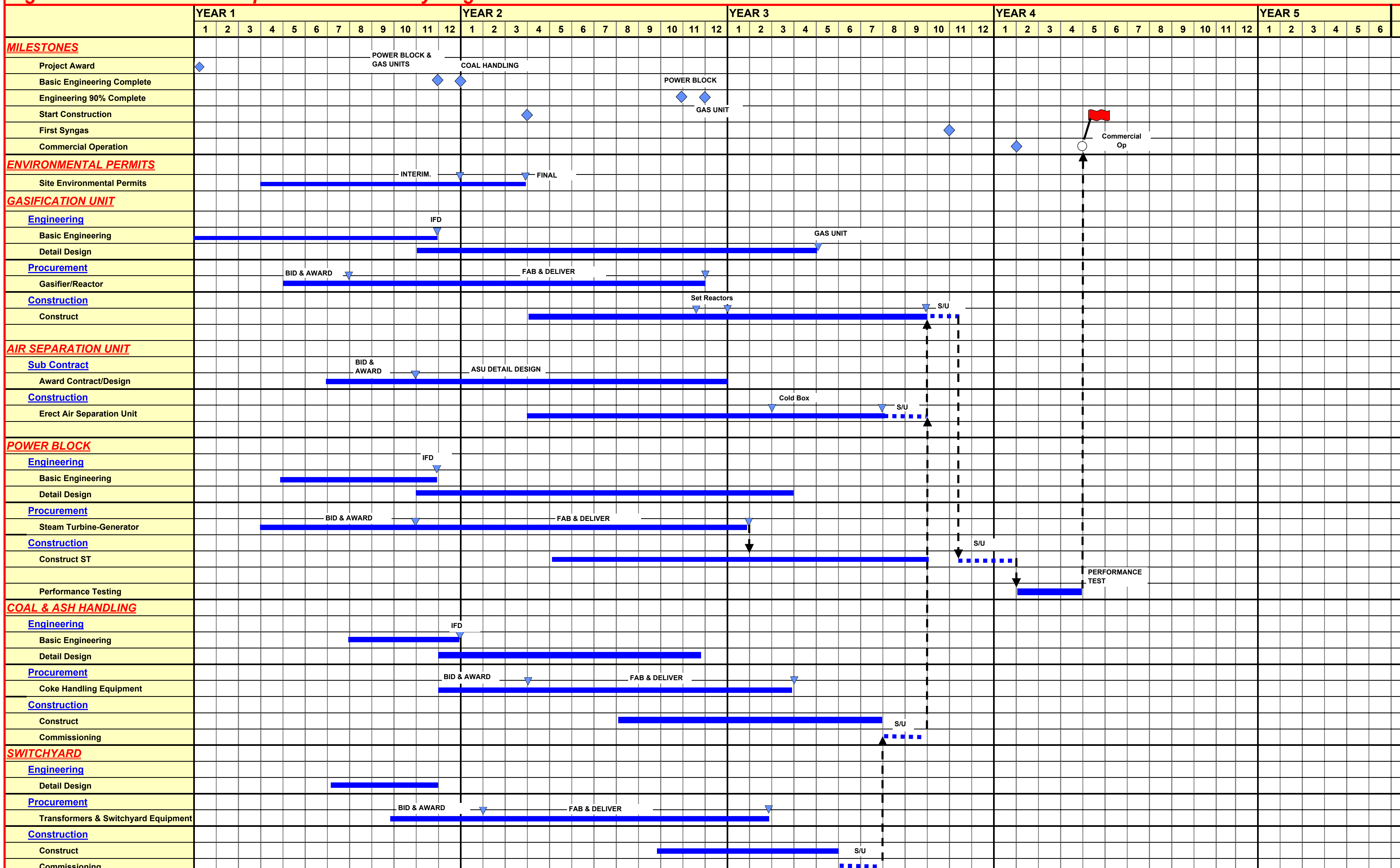
The milestone construction schedule for the major process blocks of the Coal to Power Hydrogen Plant is shown in Figure A6.

Figure A6

Milestone Construction Schedule for

the Coal to Hydrogen Plant

Figure A6 - Subtask 1.7 - Optimized Coal to Hydrogen Plant



BY	DATE	REV.
SJK	11/9/01	A++++
NS	9/7/01	A+++
SJK	8/6/01	A++
SJK	5/10/01	A+
TM	5/1/01	A

Bechtel
Houston, Texas

US DEPARTMENT OF ENERGY
Gasification Plant Cost & Performance Optimization
Subtask 1.7 Coal to Hydrogen Plant
Milestone Schedule

A.6.2 Capital Cost Summary

A.6.2.1. General

The cost estimate is a factored cost estimate based on the prior Subtask 1.3 and 1.4 cost estimates. It is an order-of-magnitude, "overnight" mid-year 2000 cost estimate. There is no forward escalation. As such, it reflects any aberrations in equipment costs based on current market conditions which were present in the original Subtask 1.3 and 1.4 cost estimates.

Major Equipment

Major equipment from Subtasks 1.1, 1.2, and 1.3 was loaded into a data base and modified to reflect the scope of Subtask 1.7. Modifications include changes in equipment duty (as a result of both capacity changes and the Design-to-Capacity VIP), quantities of equipment, and pricing. The data base also identifies the source of the cost; whether actual, from the Wabash River Repowering Project, or estimated.

The Design-to-Capacity and Classes of Plant Quality Value Improving Practices were considered in sizing the equipment for this plant. Because coal compositions can be quite variable, a range of coals were considered in the design of the Wabash River Repowering Project to provide feedstock flexibility. In Subtask 1.7, this overdesign was eliminated. Furthermore, some equipment was redesigned to reflect current engineering design practices.

Bulk Materials

Bulk material costs are factored based on the major equipment costs from the previous cases.

Subcontracts

Supply and install subcontract pricing was estimated from similar systems in prior estimates:

By Budget Quote
- Coal Handling
- Field Erected Tanks
- Air Separation Unit
- Cooling Tower (except basin)

By Unit Pricing
- Buildings including interior finish, HVAC, and Furnishings
- Fire Protection Systems
- Site Development
- Rail Spur

From the Wabash River Facility
- Painting and Insulation
- 230 KV Switchyard
- Gasifier Refractory
- Start-up Services; i.e., flushes and steam blows

Construction

Labor is based on mid-year 2000 Mid-West union shop rates and historic productivity factors. Union labor is used for installation of refractory.

Home Office Services Costs

Home office services are based on Subtask 1.1 and adjusted for the expanded scope of Subtask 1.7. Power block costs are based on current cost information.

A.6.2.2 Cost Basis

The following establish the basis of the cost summary.

- Design criteria basis are the codes, standards, laws and regulations to be compliant with U. S. and local codes for the designated region typical for U. S. installations and for the designated location of the plant.
- Subtask 1.1 - Wabash River costs adjusted from 1994 through the year 2000 Indices used are based on publicly available sources such as the Consumer Price Index, Producer Price Index, Engineering News Record Construction Cost Index, and Chemical Engineering Plant Cost Index.
- For new and highly priced equipment, current vendor quotes were obtained to reflect current market pricing.
- Site Conditions:
  - Initial site to be clean, level and clear of obstructions or contamination above and below grade
  - No layout limitations or restrictions imposed from sources external to the site
  - Soil conditions are typical for the area with no special considerations for items such as subsidence
  - Coal is delivered by rail on the north side of the site
- Cost includes only areas within the site plan
- Critical spares are included; e.g., proprietary items, one-of-a-kind items, and long lead time items. Normal warehouse, operational, and commissioning/start-up spares are excluded.
- All utilities and fuels are provided up to the battery limit of the site (exception, high voltage electrical transmission is to the HV switchyard)

The following costs are excluded:

- Contingency and risks
- Cost of permits
- Taxes
- Owner's costs such as, land, operating and maintenance equipment, capital spares, operator training, commercial test runs
- Facilities external to the site in support of the plant
- Licensing fees
- Agent fees
- Initial fill of chemicals

A.6.2.3 Capital Cost Summary

Table A4 shows the "overnight" capital cost summary by major process areas for the Optimized Coal to Power IGCC Plant.

Table A4

Capital Cost Summary of the IGCC Coal to Hydrogen Plant[2]

Plant Area	Direct Field Material	Direct Field Labor	Other Costs	Total
Solids Handling	8,900,000	7,900,000	500,000	17,300,000
Air Separation Unit	30,600,000	20,300,000	1,400,000	52,300,000
Gasification	191,500,000	43,800,000	18,900,000	254,200,000
Hydrogen Production	43,600,000	15,900,000	9,100,000	68,600,000
Power Block	50,200,000	16,000,000	14,000,000	80,200,000
Balance Of Plant	35,100,000	20,600,000	1,500,000	57,200,000
Total	359,900,000	124,500,000	45,400,000	529,800,000

A.6.2.4 Estimate Accuracy

The accuracy of the total installed cost is estimated to be on the order of ±15%. The level of accuracy reflects a high degree of confidence based on the large number of vendor quotes that were obtained and that the power block costs are based on a current similar Gulf Coast power project. This accuracy applies only to the total cost and does not apply to the individual areas or parts.

[2] All plant EPC costs mentioned in this report are mid-year 2000 order of magnitude cost estimates which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).

Appendix H

Subtask 1.7 (Appendix B)

Financial Model Analysis Input

Appendix B

Financial Analysis Model Input

Bechtel Technology and Consulting (now Nexant) developed the DCF financial model as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices task.[1] This model performs a discounted cash flow financial analysis to calculate investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of projects using IGCC systems

The required input information to the DCF financial model is organized into two distinct input areas that are called the Plant Input Sheet and the Scenario Input Sheet. The Plant Input Sheet contains data directly related to the specific plant as follows.

Data on the Plant Input Sheet

- Project summary information
- Plant output and operating data
- Capital costs
- Operating costs and expenses

Table B1 contains the data that are entered on the Plant Input Sheet for the Subtask 1.4 Optimized Coal to Power IGCC Plant both with and without the use of supplemental natural gas.

The Scenario Input Sheet primarily contains data that are related to the general economic environment that is associated with the plant. In addition, it also contains some data that are plant related. The data on the Scenario Input Sheet are shown below.

Data on the Scenario Input Sheet

- Financial and economic data
- Fuel data
- Tariff assumptions
- Construction schedule data
- Start up information

Table B2 contains the base case data that are entered on the Scenario Input Sheet for the two Subtask 1.4 cases.

[1] Nexant, Inc., "Financial Model User's Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract DE-AMO1-98FE64778, May 2000.

Table B1
Plant Input Sheet Data for Subtask 1.7

Project Inputs	**Case A**
Project Summary Data	
Project Name / Description	Subtask 1.7 Coal to Hydrogen
Project Location	Midwest
Project Type/Structure	BOO
Primary Output/Plant Application **(Options: Power, Multiple Outputs)**	Multiple Outputs
Fuel Type (**Options: Gas, Coal, Petroleum Coke, Other/Waste)**	Petroleum Coke
Plant Input/Output Flowrates - Daily Average Basis (Calendar Day)	
Syngas Capacity (MMscf/day) - Optional	0
Gross Electric Power Capacity (MW) - Optional	70.6
Net Electric Power Capacity (MW)	-15.115
Steam Capacity (Tons/hr)	0.0
Hydrogen Capacity (MMscf/day)	116.73
Carbon Monoxide Capacity (MMscf/day) - PSA Tail Gas (Low Btu Fuel Gas)	0.0
Elemental Sulfur (Tons/day)	62.8
Slag Ash (Tons/day)	389.6
Fuel (Tons/day) - **COAL**	2,470.2
Chemicals - **Natural Gas (Mscf/day) - INPUT**	0
Environmental Credit (Tons/day)	0
Other (Tons/day) - Flux **- INPUT**	0.0
Operating Hours per Year	8,760
Guaranteed Availability (percentage)	100.0%
Enter One of the Following Items Depending on Project Type:	
Heat Rate (Btu/kWh) based on HHV - Required for power projects	
Annual Fuel Consumption (in MMcf or Thousand Tons) - Required for non-power projects	901.6
Initial Capital and Financing Costs (enter 'Additional Costs' in thousand dollars)	
EPC (in thousand dollars)	529,800
Owner's Contingency (% of EPC Costs)	5.0%
Development Fee (% of EPC Costs)	1.23%
Start-up (% of EPC Costs)	1.50%
Owner's Cost (in thousand dollars) - Land	$200
Additional Capital Cost - Spares	$7,947
Additional Cost #1 - Duties, Taxes, Insurance, etc.	$1,166
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent -To be verified during project development. (in thousand dollars)	$26,490
Operating Costs and Expenses	
Variable O&M (% of EPC Cost) - **HIGHLY CONFIDENTIAL**	
Fixed O&M Cost (% of EPC Cost) - Staffing - **HIGHLY CONFIDENTIAL**	
Additional Comments: When the average daily input and output flow rates, as calculated by the availability analysis, are supplied, the guaranteed plant availability should be set to 100.0%.	Subtask 1.7 Coal to Hydrogen 11/13/01

Table B2
Scenario Input Sheet Data for Subtask 1.7
(Page 1 of 5)

Project Name / Description	Subtask 1.7 Coal to Hydrogen
Project Location	Midwest
Project Type/Structure	BOO

Capital Structure	
Percentage Debt	80%
Percentage Equity	20%
Total Debt Amount (in thousand dollars) - **CALCULATED**	---

Project Debt Terms	
Loan 1: Senior Debt	
% of Total Project Debt **(total for Loans 1,2, and 3 must = 100%)**	100%
Loan Amount (in thousand dollars) - **CALCULATED**	---
Interest Rate	10%
Financing Fee	3%
Repayment Term (in Years)	15
Grace Period on Principal Repayment	0
First Year of Principal Repayment	2003
Loan 2: Subordinated Debt	
% of Total Project Debt	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0
Interest Rate	8%
Financing Fee	3%
Repayment Term (in Years)	15
Grace Period on Principal Repayment	1
First Year of Principal Repayment	2004
Loan 3: Subordinated Debt	
% of Total Project Debt	0%
Loan Amount (in thousand dollars) - **CALCULATED**	0
Interest Rate	7%
Financing Fee	3%
Repayment Term (in Years)	10
Grace Period on Principal Repayment	1
First Year of Principal Repayment	2004

Loan Covenant Assumptions	
Interest Rate for Debt Reserve Fund (DRF)	5%
Debt Reserve Fund Used on Senior Debt **(Options: Yes or No)**	Yes
Percentage of Total Debt Service used as DRF	20%

Depreciation	
Construction (Years)	7

Table B2
Scenario Input Sheet Data for Subtask 1.7
(Page 2 of 5)

Financing (Years)	7

Working Capital	
Days Receivable	30
Days Payable	30
Annual Operating Cash (in thousand dollars)	100
Initial Working Capital (% of first year revenues)	0%

ECONOMIC ASSUMPTIONS

Cash Flow Analysis Period	
Plant Economic Life/Concession Length (in Years)	20
Discount Rate	12%

Escalation Factors	
Project Output/Tariff	
Syngas	1.7%
Electricity: Capacity Payment	1.7%
Electricity: Energy Payment	1.7%
Steam	3.1%
Hydrogen	3.1%
Carbon Monoxide	1.7%
Elemental Sulfur	0.0%
Slag Ash	0.0%
Fuel (IGCC output)	0.0%
Chemicals - **Natural Gas**	3.9%
Environmental Credit	1.7%
Other **- Flux**	1.7%
Fuel/Feedstock	
Gas	3.9%
Coal	1.2%
Petroleum Coke - **Used for COAL in Petroleum Coke Option**	1.2%
Other/Waste	2.3%
Operating Expenses and Construction Items	
Variable O&M	2.3%
Fixed O&M	2.3%
Other Non-fuel Expenses	2.3%

Tax Assumptions	
Tax Holiday (in Years)	0
Income Tax Rate	40%
Subsidized Tax Rate (used as investment incentive)	0%
Length of Subsidized Tax Period (in Years)	0

Table B2
Scenario Input Sheet Data for Subtask 1.7
(Page 3 of 5)

FUEL/FEEDSTOCK ASSUMPTIONS

Fuel Price	
Gas ($/Mcf)	2.60
Coal ($/Ton)	22.0
Petroleum Coke ($/ton) - **Used for COAL in Petroleum Coke Option**	22.0
Other/Waste ($/Ton)	14.00

Heating Value Assumptions	
HHV of Natural Gas (Btu/cf)	1,000
HHV of Coal (Btu/kg)	28,106
HHV of Petroleum Coke (Btu/kg), Dry basis - **Used for Coal**	28,106
HHV of Other/Waste (Btu/kg)	0

TARIFF ASSUMPTIONS

INITIAL TARIFF LEVEL (In Dollars in the first year of construction)	
Syngas ($/Mcf)	$0
Capacity Payment (Thousand $/MW/Year)	$0
Electricity Payment ($/MWh)	$27.00
Steam ($/Ton)	$5.60
Hydrogen ($/Mcf) - **Base value is shown - Varied for Financial Analysis**	$1.30
Carbon Monoxide ($/Mcf)	$0.2274
Elemental Sulfur ($/Ton)	$30.00
Slag Ash ($/Ton)	$0
Fuel ($/Ton)	$0
Chemicals - **Natural Gas ($/Mscf)**	$2.60
Environmental Credit ($/Ton)	$0
Other ($/Ton) - **Flux**	$5.00

CONSTRUCTION ASSUMPTIONS

Construction Schedule	
Construction Start Date	9/1/1999
Construction Period (in months) - Maximum of 48	40
Plant Start-up Date *(must start on January 1)*	1/1/2003

Percentage Breakout of Cost over Construction Period (each category must total 100%)	
Year 1	
EPC Costs - See Note 1.	6.82%
Initial Working Capital	0%
Owner's Contingency	0%
Development Fee	0%
Start-up Costs	0%

Table B2
Scenario Input Sheet Data for Subtask 1.7
(Page 4 of 5)

Initial Debt Reserve Fund	0%
Owner's Cost - Land	70%
Additional Capital Costs - Spares	0%
Financing Fee	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	6.82%
Year 2	
EPC Costs - See Note 1.	36.00%
Initial Working Capital	0%
Owner's Contingency	0%
Development Fee	100%
Start-up Costs	0%
Initial Debt Reserve Fund	0%
Owner's Cost - Land	30%
Additional Capital Costs - Spares	0%
Financing Fee	100%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	36.00%
Year 3	
EPC Costs - See Note 1.	31.81%
Initial Working Capital	0%
Owner's Contingency	0%
Development Fee	0%
Start-up Costs	30%
Initial Debt Reserve Fund	0%
Owner's Cost - Land	0%
Additional Capital Costs - Spares	0%
Financing Fee	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	50%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	31.81%
Year 4	
EPC Costs - See Note 1.	27.37%
Initial Working Capital	100%
Owner's Contingency	100%
Development Fee	0%
Start-up Costs	70%
Initial Debt Reserve Fund	100%
Owner's Cost - Land	0%
Additional Capital Costs - Spares	100%

Table B2
Scenario Input Sheet Data for Subtask 1.7
(Page 5 of 5)

Financing Fee	0%
Additional Cost #1 - Duties, Taxes, Insurance, etc.	0%
Additional Financing Cost #1 & Allowance for EPC Contingency, Risk and Fees - Project Dependent - To be verified during project development. See Note 1.	27.37%

Plant Ramp-up Option (Yes or No)	Yes

Start-Up Operations Assumptions (% of Full Capacity)	
Year 1, First Quarter	25.0%
Year 1, Second Quarter	50.0%
Year 1, Third Quarter	75.0%
Year 1, Fourth Quarter	90.0%
Year 1 Average Capacity %	60.0%
Year 2, First Quarter	100.0%
Year 2, Second Quarter	100.0%
Year 2, Third Quarter	100.0%
Year 2, Fourth Quarter	100.0%
Year 2 Average Capacity %	100.0%

CONVERSION FACTORS	
kJ to Btu	0.94783
Btu to kWh	3,413
kg to English Ton	1,016
kW per MW	1,000
kJ/kWh	3,600
Gallons Equivalent to 1 Barrel of Crude Oil	42
Cubic Feet to Cubic Meter	0.02832
Months per Year	12
Hours per Day	24
10^6 (for conversion purposes)	1,000,000
Hours per year	8,760

Note 1. The total is greater than 100% to account for inflation during construction.

Appendix I - Subtask 1.8

Warm Gas Cleanup Review

Appendix I – Subtask 1.8

Executive Summary

Sulfur removal is a necessary, but a costly part of an IGCC plant. All of the study cases include facilities to allow greater than 98% sulfur removal and recovery. These facilities include: COS hydrolysis, low temperature cooling to 100°F or less, sour water stripping (SWS), gas treating (acid gas removal (AGR)) to separate sulfur compounds, Claus sulfur recovery, and a tail gas recycle compressor (in place of a tail gas treating unit (TGTU)). The sulfur removal system design will also impact the design and cost of the upstream chloride scrubbing/removal system, recycle compressor, and downstream syngas moisturization equipment. The objective of this study is to identify a system operating at temperatures closer to 700°F, (between 300 and 750°F), thereby eliminating most of the low temperature cooling system and reducing the cost.

Bechtel and Global Energy searched the available literature for information on warm gas cleanup (WGCU) systems. The study team also considered several conceptual designs and options for various sub-system components. However, only a novel WGCU system proposed by Global Energy, which is similar to hot gas cleanup systems, satisfied the study design criteria. Further review of capital and operating cost showed this WGCU currently is not competitive with the base case amine low temperature acid gas removal (AGR) system.

This report summarizes the findings of the WGCU review and the associated cost analysis. Table ES-1 compares the estimated capital and operating cost differences for the WGCU's considered in this study. The table shows that amine systems (including COS hydrolysis and cooling to low temperatures) are very cost effective for removal of sulfur species down to about 20 ppm in the syngas (99% removal). Physical solvents, such as Rectisol (and Selexol), can remove sulfur compounds down to 1 ppm, but are more expensive and may remove significant amounts of syngas and carbon dioxide (gas turbine diluent). The entire amine sulfur recovery system is estimated to cost 60 MM$, but potential savings in capital cost through removal of the low temperature gas cooling equipment, is approximately 10 MM$. The Subtask 1.4 cost sensitivity table (Table 7) shows that reducing cost by 10 MM$ will increase the plant ROI by about 0.8% (or will reduce the cost of electricity by just less than 0.6 $/MW-hr). However the cost savings are likely to be offset by cost increases elsewhere. Therefore to achieve significant cost savings, which would promote selection of a new or novel WGCU technology over an amine system, a WGCU system should be a simple, direct (one or two step) process which combines many of the steps listed above.

Selective Catalytic Oxidation of Hydrogen Sulfide (SCOHS), which is being developed by DOE/NETL was also reviewed. SCOHS operates at a slightly lower temperature than specified for WGCU, and therefore was excluded from the WGCU comparison. However, the study team found that SCOHS has the potential to be a simple low cost process for IGCC plants. Also, several additional subsystems are required to make SCOHS an acceptable substitute for the amine based sulfur removal system. These sub-systems are: pre-cooling to 225°F, chloride removal, trace element and ammonia removal, sour water stripping, syngas re-heating and moisturization. The report also discusses the research needs and impediments to commercialization such as: simultaneous COS hydrolysis or COS reaction to sulfur; operating at higher temperatures to avoid water or sulfur condensation; regeneration testing, and regeneration at lower temperatures (<650°F). If testing and development are successful, this system should be less costly than an amine based system and achieve lower sulfur emissions.

Table ES-1

Warm Gas Cleanup (WGCU) Comparison

GAS CLEANUP SYSTEM	WGCU	Technical Feasibility	Estimated TIC	O&M								Remarks
				CO_2 Slip %	Stm.	Ad sorb ent	PWR	N_2	Syn gas	Solvent Cats & Chems	Total O&M	
MDEA	N	Proven	Base	85	Base	NA	Base	NA	Base	MDEA Base	Base	Baseline/Current design
RTI Membrane Process	N	R&D	1.15xBase	100	NR	Base RVS	> Base	yes	> Base	Memb. > Base	> Base	Uses a Membrane at 80°F & passes H_2 – Separation difficult.
Global Energy Proposed Process	Y	R&D ++	1.4xBase	100	(rgn heat) > Base	8x Base	> Base	yes	> Base	PSA Mol-sieve > Base	> Base	PSA needs verification & development. Adsorbent attrition.
Rectisol	N	Proven	1.5xBase	10-90	> Base	NA	> Base	yes	Base	MEOH > Base	> Base	Limited to H_2S removal. Requires Refrigeration
SCOHS Plus (1)	N	Early R&D	0.8xBase	100	(rgn heat) > Base	Car-bon > Base	> Base	yes	> Base	O_2 > Base neg.	> Base	Temp.<300°F. H_2S removal limited. COS not tested.
Iron Oxide	Y	Pilot/ Demo	>Base	100	(rgn heat) > Base	Iron > Base	> Base	yes	> Base	O_2 > Base neg.	> Base	Limited sulfur recovery and regeneration testing. Lock hoppers required.

1- Process steps – Gas cooling - COS conversion – SCOHS – PSA (NH_3 and trace element removal) – Syngas heating – Regeneration – Sulfur condenser – Compression for SCOHS and PSA regeneration gas.

Appendix I – Subtask 1.8

Warm Gas Cleanup Review

1.0 Introduction

The U. S. Department of Energy's Vision 21 program expects that Integrated Gasification Combined Cycle (IGCC) systems will have a major role for the continued use of solid fossil fuels. The Vision 21 concept envisions a virtually pollution-free energy plant that will produce multiple products in addition to electricity, such as liquid fuels, chemicals, hydrogen, steam, and/or industrial process heat. It also could process a wide variety of fuels such as coal, petroleum coke, biomass, and municipal waste. The Vision 21 plant would generate electricity at unprecedented efficiencies, and coupled with carbon dioxide sequestration technologies, it would emit little if any greenhouse gases into the atmosphere. Vision 21, if successful, could revolutionize the power and fuels industry within the next 15 years, and be a cornerstone of sustainable economic development.

The challenge is that IGCC plants, including the sulfur removal system, are capital cost intensive systems. Therefore many optimization studies focus on enhancements to reduce the capital and operating costs with the hope of making these plants more competitive. Development and testing of Hot Gas Cleanup systems is one of these initiatives. Several studies/projects evaluated and planned tests based on high temperature adsorbents. Unfortunately these adsorbents have not yet lived up to commercial expectations, primarily due to the harsh high temperature environment. The objective of this study is to improve the economics of a coal or coke IGCC plant by inclusion of a novel Warm Gas Cleanup (WGCU) system. These systems are targeted for milder temperatures (300 to 750^{o}F) and moderate savings. The common measures of financial success, such as return on investment (ROI), net present value (NPV), and payback period all are dependent on the capital and operating costs.

This report is divided into the following sections:

2.0 Comparison Basis – This section reviews the study design basis and objectives
3.0 Methodology – This section reviews the study activities related to data gathering
4.0 WGCU System Descriptions – This section describes the three most promising systems and SCOHS
5.0 WGCU System Comparison - This section compares the cost of WGCU systems with the base case amine AGR system and its associated subsystems.
6.0 Summary – This section discusses study findings and recommendations.

Attachment A, Technical Information, contains a list of reference materials used in the evaluation.

2.0 Comparison Basis

The basis and starting point for this study is Subtask 1.4, the future advanced coal to power plant, that uses the next generation of Global Energy gasifier and advanced "H-class" gas turbine technology. The Subtask 1.4 design includes an amine-based gas treating system similar to that currently in use at the Wabash River IGCC plant. Figure 1 is a block flow diagram of the amine based sulfur recovery system and associated process steps. The Subtask 1.4 report contains additional performance and cost information.

The study scope of work included a review of the status of available hot gas cleanup technologies and a search for new developing technologies over a moderate (warm) temperature range from 300°F to 750°F (extended from 500 down to 300°F by DOE). This is the temperature of raw syngas from the chloride scrubber or the high temperature heat recovery boiler, respectively. Therefore, this is the preferred temperature region for adding the WGCU system to Global's gasification technology. The primary objective of this study is to develop a design for the most promising technology applied to the Subtask 1.4 design and to provide an estimate of the potential savings from implementation. Deliverables include a IGCC plant performance estimate, a factored cost estimate, and a financial assessment similar to previous reports.

The technical plan for this work contains a set of design criteria. It is assumed the WGCU system can achieve the same level of sulfur removal as the base case amine system (20 ppmv of H_2S in the treated syngas and low levels of COS (achieved with COS hydrolysis)). Additional sulfur removal requires physical solvents such as Rectisol or Selexol and possibly ZnO adsorbents for trace sulfur removal. The chosen WGCU system should also include systems to remove mercury and other trace elements as may be required in the future.

3.0 Methodology For Evaluation of WGCU Technology and Criteria For Selection

The first step was to identify potential WGCU systems. This was accomplished by: reviewing previous hot gas cleanup system experience; meetings to define the required components of a WGCU system including their function and/or duty specifications; a literature search for information on system components; meetings to review the gathered information; and a preliminary process design for the candidate system.

The Hot Gas Cleanup review briefly touched on the work done at Tampa Electric, Pinion Pine, NEDO in Japan, RTI on adsorbent development, and ongoing DOE/NETL GPDU developments. A recent review of this technology considered the merits of continuing the work on the GPDU, and highlighted the need for more robust, attrition resistant adsorbents that can tolerate the temperatures and regeneration reaction effects/dynamics. Ongoing tests in the GPDU have been disappointing and show that suitable adsorbents have not yet been identified. Furthermore, additional work is needed to identify systems for SO_2 reduction to sulfur, systems for removal of HCN, NH_3, chlorides, and other minor components and systems for removal of trace metals. Development of successful WGCU systems will have to address these same considerations.

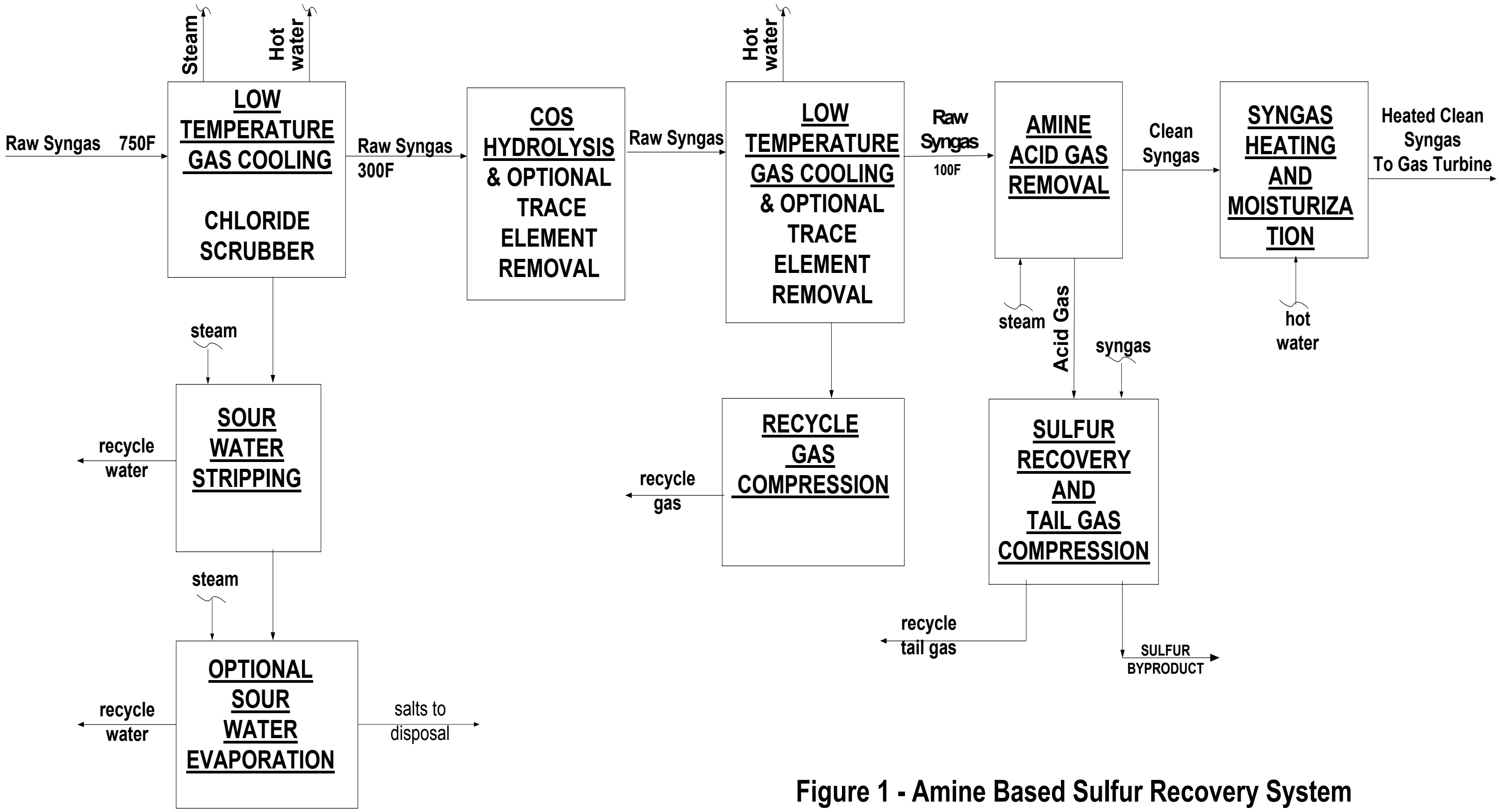


Figure 1 - Amine Based Sulfur Recovery System

A literature search and team discussion identified the following systems as potential candidates for WGCU or for comparison with a WGCU system:

RTI Membrane Process (Reference 1)
Global Energy's Proposed Design
Rectisol (Reference 3)
Iron Oxide (References 4 and 5)
SCOHS (Reference 6)

The RTI Process and Rectisol are low temperature and cryogenic systems, respectively. The RTI system uses a membrane and near ambient conditions to precondition the gas. The membrane reduces the sulfur load on the adsorbent thereby improving economics. However, this requires cooling to near 100^{o}F, thereby eliminating it from consideration for a WGCU.

The Rectisol process was included here because it can completely remove most of the sulfur compounds in the syngas. However, because Rectisol uses refrigeration and cryogenic operating conditions, it is a high cost system. The Rectisol process uses methanol as a physical solvent and can remove H_2S and COS to less than 1 ppmv. It is currently used in the Tennessee Eastman plant to clean the gas upstream of the CO cold box and methanol synthesis. Rectisol is typically used upstream of chemical synthesis to remove sulfur species to less than 1 ppm, and CO_2, if needed.

Of the remaining systems only the Global Energy System, and Iron Oxide have the characteristics of a WGCU system. The Global Energy system BFD is shown in Figure 2. This system uses the DOE-developed RVS adsorbent without membrane separation. The Iron Oxide system is similar to typical hot gas cleanup systems, except that the adsorption of H_2S takes place at lower temperatures.

In addition to sulfur removal, a WGCU should have the ability to meet future pollution control requirements by controlling other pollutants such as chlorides, mercury, and trace metals such as selenium and arsenic. Therefore, a literature search was made to identify suitable processes for these pollutants. The search identified Nacholite for chloride removal, PSA for ammonia removal, and activated carbon or molecule sieves for trace element removal. These systems were included in the Global energy proposed system. Also DOE is funding a project by Micronbeam Technology to investigate Mercury removal at mild temperatures. Some of the preliminary results were encouraging.

Several additional systems such as propylene carbonate and hot carbonate (in general), were discussed, but did not make the short list because of technical limitations and technology uncertainties.

SCOH's operates at slightly lower than the 300-750^{o}F temperature range selected at the outset of the study. There also is concern about oxygen addition to syngas and subsequent combustion. However it was selected for further discussion because it has several promising attributes, one of which is that it has the potential to be a fairly simple system.

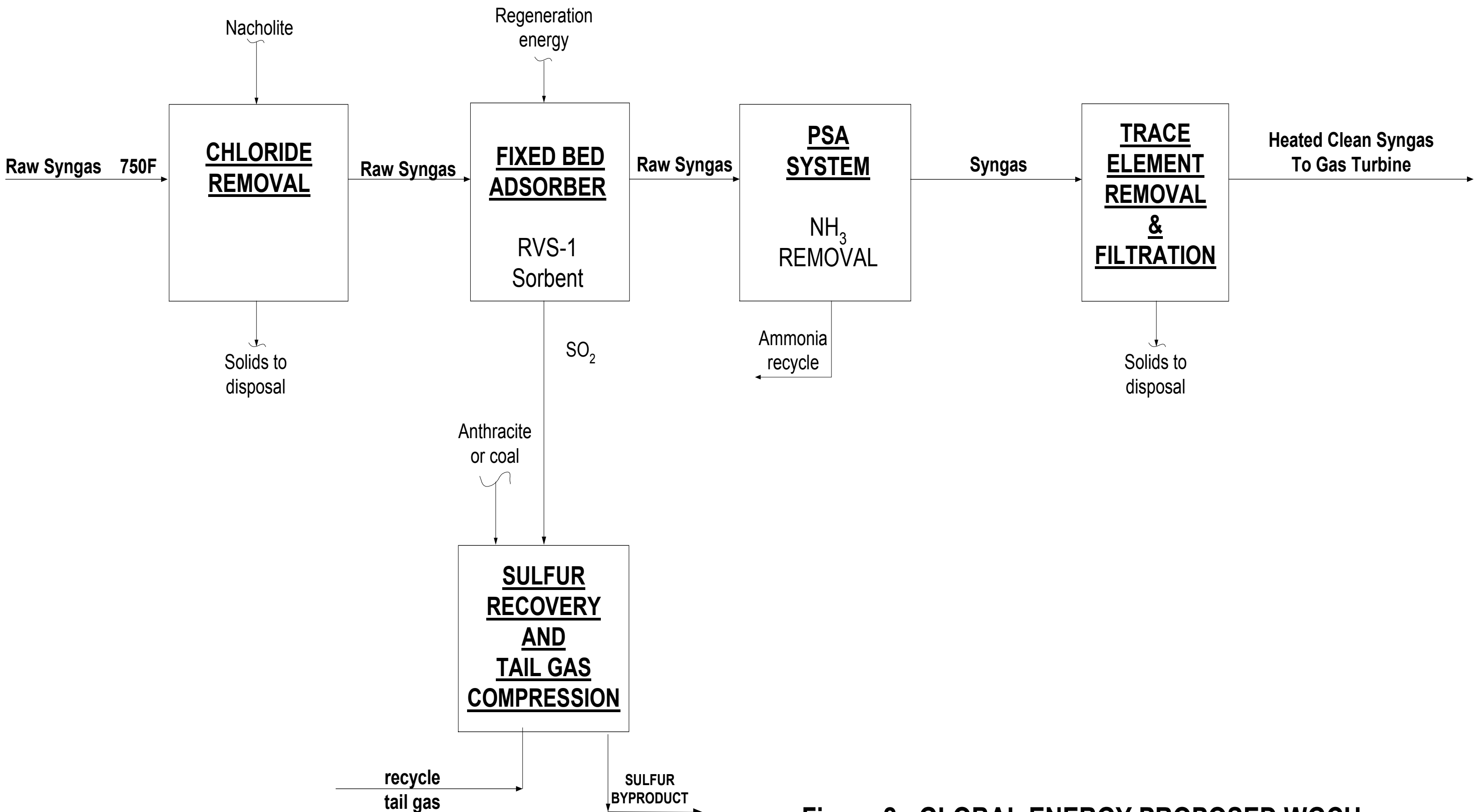


Figure 2 - GLOBAL ENERGY PROPOSED WGCU

4.0 WGCU System Descriptions

4.1 Global Energy Proposed Process

Bechtel and Global agreed to evaluate Global's proposed cleanup scheme. The system shown in Figure 2 includes: chloride removal, DOE-developed RVS-1 adsorbent for sulfur removal, NH_3 removal via Pressure Swing Adsorption (PSA), and activated carbon for trace element removal. SO_2 from adsorbent regeneration at 1000-1100^oF will be reduced to sulfur over anthracite or coal.

Solid adsorbent systems generally are used for polishing because they have low capacity. DOE has developed a solid adsorbent system called RVS-1. The adsorbent was evaluated by RTI under a DOE contract. Results show that it removes H_2S to less than 20 ppmv. It can be regenerated at 1000-1100^oF. In a moving bed it is expected to have a high attrition rate. Sud Chemie was selected to produce commercial quantities of the adsorbent.

Addition of a Nahcolite bed to remove chlorides prior to RVS-1 (or iron oxide) is necessary to maximize the adsorbent life.

A PSA system with HY zeolite has been patented. It has not been tested and may have potential.

There is not much information available for trace volatile metals (Hg, Se, As) removal. Micronbeam Technology Inc. (MTI) is a completing DOE-funded project to investigate removing mercury in a reducing atmosphere at 300^oC (572^oF). Global proposes to use Micronbeam technology for mercury removal and activated carbon to remove other trace elements. These systems have not been fully tested, but they appear to have potential. Mersorb, a sulfur impregnated carbon made by Nucon International, or similar may be an option up to 390^oF.

4.2 Iron Oxide

Figure 3 shows a schematic of the HGCU unit being developed by NEDO in Japan for the national IGCC program. This system has the highest operating temperature of all the systems under consideration. It is essentially a HGCU system that can operate at warm temperature conditions.

Use of iron oxide for "hot gas desulfurization" was extensively studied in Japan starting in 1979 in a national IGCC development program. The development effort evolved from bench scale to the demonstration of the iron oxide process in a 200 t/d coal gasification pilot plant in 1992-95. The chemistry follows:

$$3\,Fe_2O_3 + H_2/CO = 2\,Fe_3O_4 + H_2O/CO_2 \quad \text{(Sorbent reduction)}$$
$$Fe_3O_4 + 3\,H_2S + H_2 = 3\,FeS + 4\,H_2O \quad \text{(Sulfur removal)}$$
$$4\,FeS + 7\,O_2 = 2\,Fe_2O_3 + 4\,SO_2 \quad \text{(Sorbent oxidation / regeneration)}$$

Several articles describing the development of the Iron Oxide system have been located and reviewed. The key information is summarized as follows:

Figure 3

Schematic Flow Sheet of the

Hot Gas Desulfurization Unit

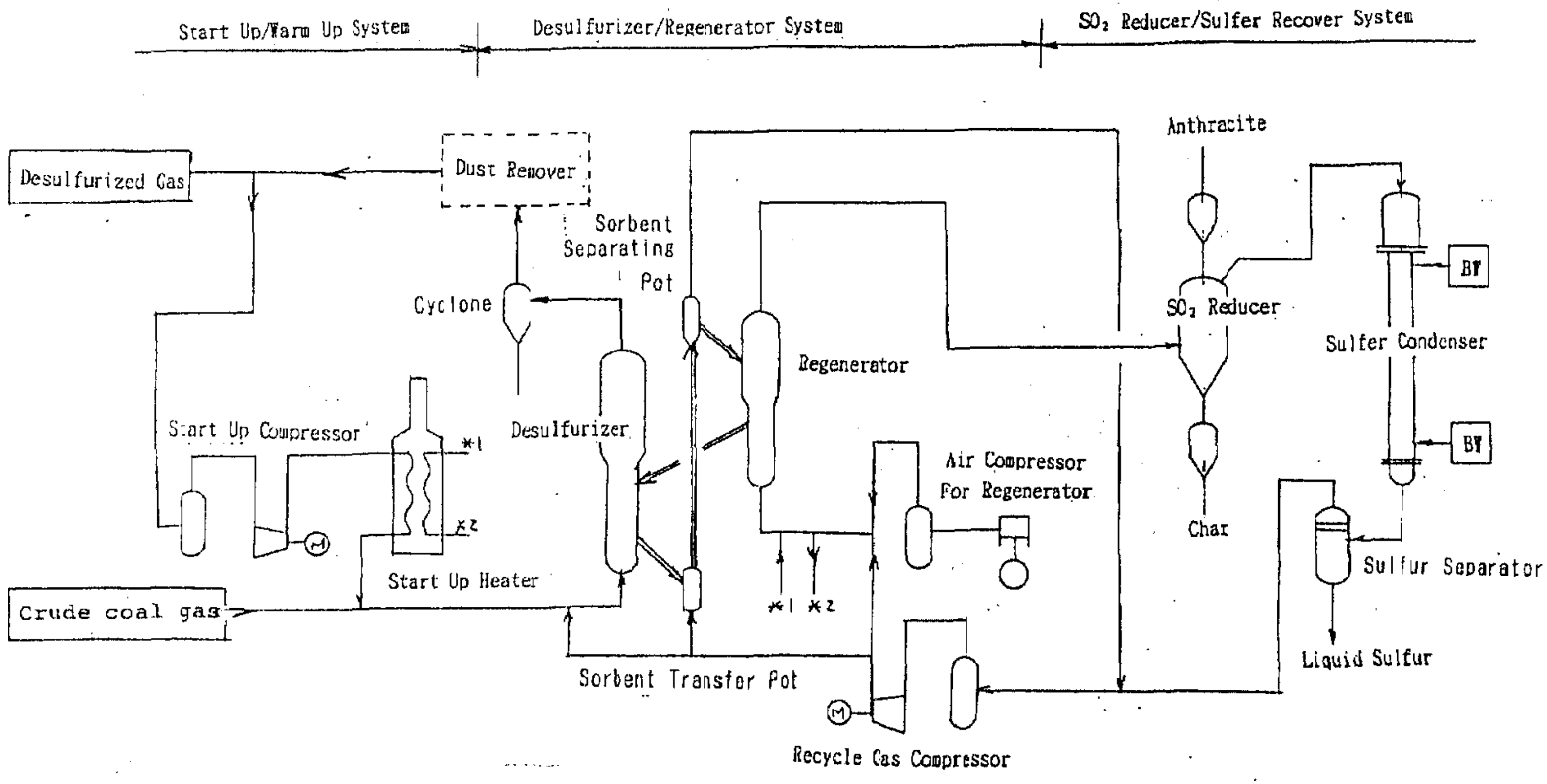


Fig.3
Schematic Flow Sheet of The Hot Gas Desulfurization Unit

IHI paper (additional)

- The desulfurization reaction takes place at 650-800^oF. Regeneration reaction is highly exothermic, at 900-1100^oF
- Fluid bed, moving bed, and fixed bed configurations were investigated in the laboratory and on a pilot plant scale.
- Crushed iron ore was used in the fluid bed process. Iron on silica or titania supports were more reactive, but they had very poor attrition resistance (ten times worse than iron ore).
- The H_2S equilibrium concentration is very sensitive to the moisture content of the syngas. At the 15-25% moisture content in the raw syngas for slurry-fed gasification systems, H_2S concentrations at the exit of the sorbent bed would be between 50-130 ppm depending on the operating temperature of the sorbent. At the designed condition of 10% moisture for the Japanese process (dry feed, air), total residual sulfur averaged 50 ppm.
- High moisture content negatively affects the residual sulfur content in the syngas for both zinc oxide and iron oxide systems by the equilibrium reaction:
  $MO + H_2S \Longleftrightarrow MS + H_2O$
- Since ZnS is more stable than FeS, the residual H_2S will be higher for iron oxide systems. The RTI evaluation for RVS-1 was conducted with syngas at 18% moisture. Residual H_2S of 20 ppmv or less was achieved. At similar moisture content for iron oxide systems, equilibrium H_2S concentration would be in the 80-120 ppmv, depending on the operating temperature.
- The moving bed design also functions as both a dust removal as well as a sulfur removal unit. Iron on a spherical alumina-silica porous support was used. No reduction in reactivity or strength was observed after 2,000 cycles. The moving bed design was reported to have good dust removal performance.
- Iron oxide-titanium oxide supported on a honeycomb substrate was used in the fixed bed design. Each reactor has four honeycombs staged in series.
- The target for the Japanese national program was to remove sulfur to 100 ppm at 700-800^oF. The choice of iron oxide is appropriate for this level of sulfur removal and temperature range.

Based on the Japanese work, the iron oxide process seems to be a viable process in removing sulfur contaminants from syngas at the temperature range of 650-800^oF. However, a polishing bed is necessary if a lower residual sulfur level is desired. The iron oxide process is very similar to the zinc-titanate processes (fluid, moving, and fixed bed), except that it operates at a slightly lower temperature and leaves a higher residual sulfur content in the syngas. The fixed bed process is probably equivalent to RVS-1.

An interesting fact from the fluid bed pilot plant work was that it used a direct reduction process with anthracite (or coal) to convert the SO_2 to elemental sulfur:

$2\,C + 2\,SO_2 = 2\,CO_2 + S_2$

Due to its simplicity, the process probably is a suitable replacement for RTI's DSRP process.

However, the regeneration step, which was found to be difficult in HGCU projects in the United States, did not quite reach the desired higher target temperature because of the low sulfur content in the coal and syngas. Therefore the test did not achieve the desired conversion target. Because of limited H_2S removal and regeneration testing, the Iron Oxide system was dropped from consideration.

4.3 Selective Catalytic Oxidation of Hydrogen Sulfide

As noted above Selective Catalytic Oxidation of Hydrogen Sulfide (SCOHS) has the potential to be a simple cost effective system. Following is a brief review and discussion of these characteristics.

The SCOHS technology is currently being sponsored at NETL integrates gas conditioning (e.g. amine or HGD) and gas treating (e.g. Claus or DSRP) systems into a single overall step. The result is a simpler, lower cost system for attaining a sulfur free coal-derived synthesis gas. Thermodynamically, this reaction can remove hydrogen sulfide to the part-per-billion (ppb) level. Experimentally, parts-per-million and ppb hydrogen sulfide exit concentration levels have been observed. Additionally, the process is highly selective toward elemental sulfur production. Current research is focused on developing engineering design parameters for scale-up and modeling of the process.

The SCOHS process is depicted in Figures 4 and 5. For this process evaluation, the SCOHS catalyst is assumed to be activated carbon. The activated carbon catalyst has an estimated life of one year and may be disposed of as gasification feedstock at the end of its useful life. In this process, the microporous catalyst simultaneously catalyzes the reaction

$H_2S + ½\,O_2 = S + H_2O$

and acts as a medium for storage of the sulfur product. Over time the catalyst becomes fouled with sulfur and must be regenerated. It is assumed that the catalyst gains up to 50 percent by weight before regeneration. Daily catalyst regeneration is required.

Regeneration occurs at 650^{o}F with low pressure nitrogen that drives off the elemental sulfur and restore catalyst activity. All hydrogen sulfide is converted to elemental sulfur; however, since coal-derived syngas contains high concentrations of carbon monoxide, small amounts of carbonyl sulfide (COS) may be generated (CO + S = COS). The net result of this process is an ultra-clean coal-derived synthesis gas.

As depicted in Figure 5, raw coal gasifier gas is received at the SCOHS plant at 275^{o}F. This gas is contacted with air in the presence of an oxidation catalyst in either a fixed or fluidized bed reactor. The hydrogen sulfide is converted to elemental sulfur via the reaction:

$H_2S + ½\,O_2 = S + H_2O$

Coolant may be required to maintain the reactor at isothermal conditions. Catalyst fines are removed in down stream filter beds. The product is retained within the micropores of the catalyst until thermal regeneration occurs. Once fully saturated with sulfur, nitrogen is used to thermally desorb the sulfur from the catalyst. Once the catalyst is cleaned, activity is fully restored. Catalyst fines are removed in down stream filter beds. Residual hydrogen sulfide and trace elements are removed with activated carbon, and ammonia is removed in a downstream PSA (or molecular sieve bed). Finally, the cleaned syngas is reheated using the heat extracted from the SCOHS reactor and by heat exchange with the process inlet stream.

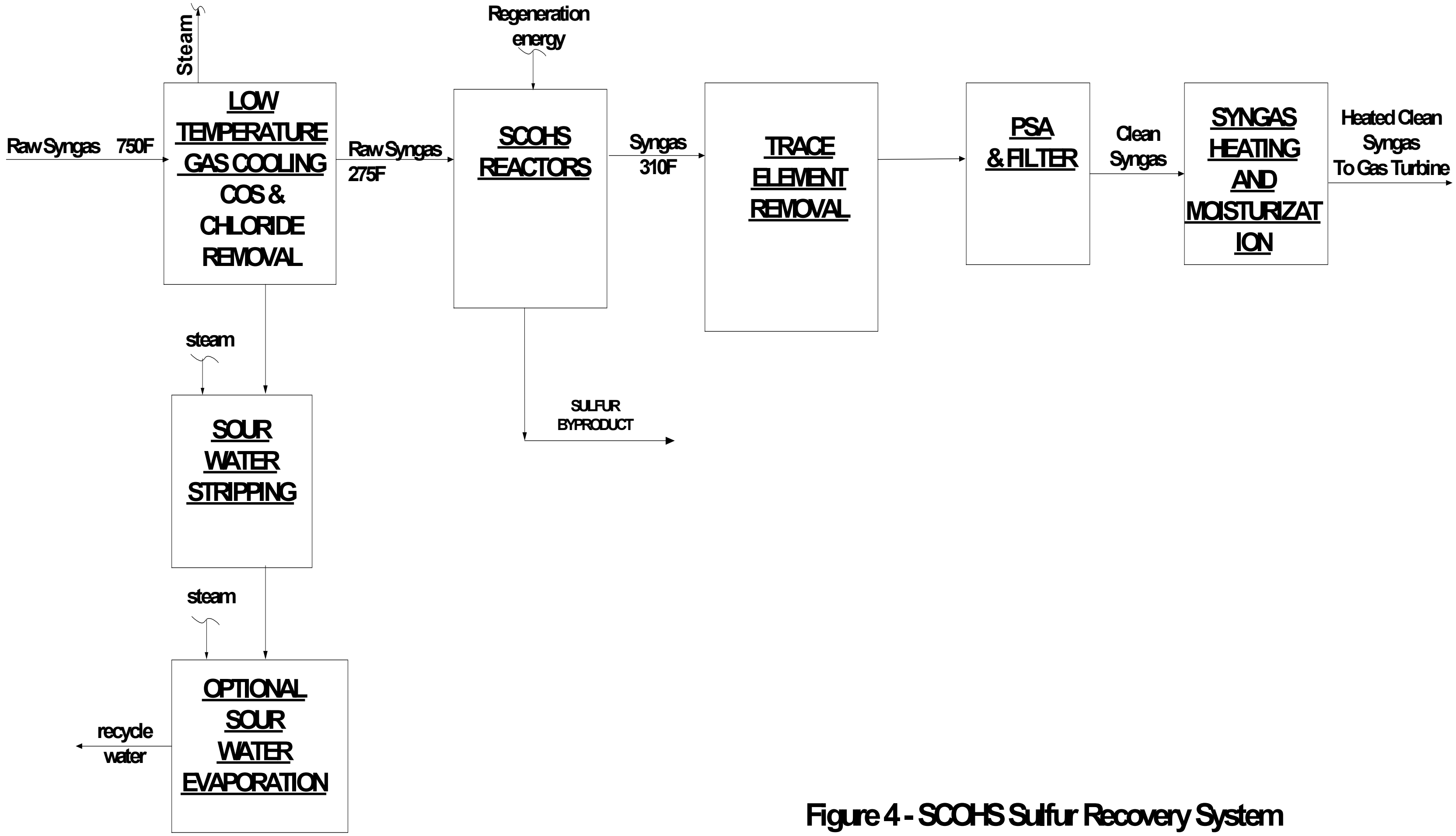


Figure 4 - SCOHS Sulfur Recovery System

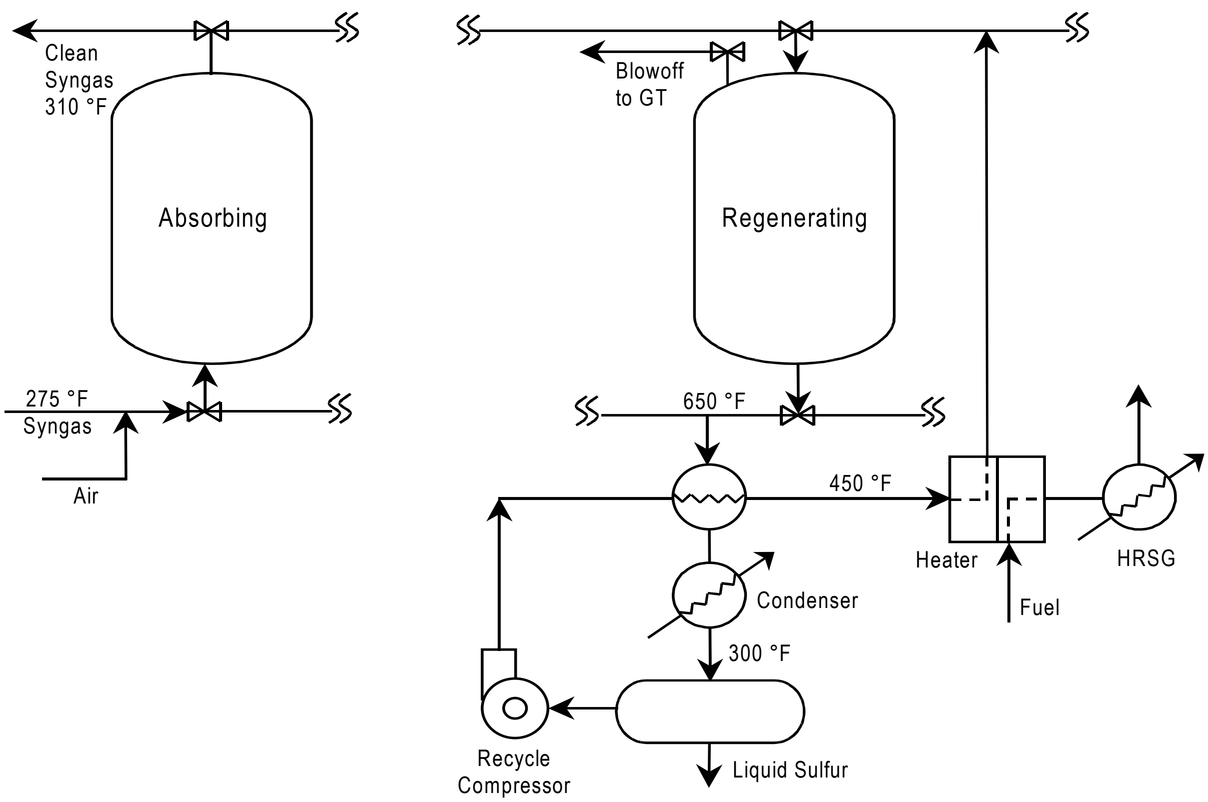


FIGURE 5 –SCOHS REACTION SYSTEM

Following is a list of questions and uncertainties that need to be resolved prior to commercialization of SCOHS:

Is cooling and gas conditioning to below the dew point (e.g. below 225°F) required to allow operation at the inlet temperature of 275°F to prevent condensation and catalyst damage? Is it possible to operate with an inlet temperature of 350°F (similar to COS hydrolysis)?

Confirm catalyst performance in a demonstration plant. Confirm carbon consumption is minimal.

Confirm that safe controllable operation is possible with air (or oxygen) injection in hydrogen and syngas.

Evaluate capture of other trace components such as Hg, Cl, NH_3, As, Se, etc. Confirm loading and method for regeneration or disposal.

Confirm sulfur recovery. (Are two beds required in series)?

Confirm sulfur pickup and regeneration cycle.

Confirm coolant is required to control the reaction. Can the syngas be reheated?

Is downstream H_2S or sulfur removal required?

Is COS formed, converted or hydrolyzed allowing recovery? Is a separate hydrolysis system required?

Check for any other side reactions.

What is the minimum temperature required for regeneration? Confirm regeneration scheme. Are there other sources of regeneration gas?

Confirm catalyst supplier and system pressure drop.

Hopefully, basic research and pilot plant testing will allow DOE/NETL to resolve most of these questions.

5.0 WGCU System Comparison

Table 1 includes a comparison of the capital and operating costs of the various systems considered for this analysis. As shown none of the systems are competitive with the base case Amine system. As the sulfur removal requirements increase, some of these systems may become more cost effective.

This table shows that amine systems (including COS hydrolysis and cooling to low temperature) is very cost effective for removal of sulfur species down to about 20 ppm in the syngas (99% removal). Physical solvents, such as Rectisol (and Selexol), can remove sulfur compounds down to 1 ppm, but they are more expensive and may remove significant amounts of syngas and carbon dioxide (gas turbine diluent). The entire amine sulfur recovery system is estimated to cost 60 MM$, but potential savings in capital cost through removal of low temperature gas cooling equipment, is only approximately 10 MM$. The Subtask 1.4 cost sensitivity table (Table 7) shows that reducing cost by 10 MM$ will increase plant ROI by less than 0.8% (or reduce the cost of electricity by just less than 0.6 $/MW-hr). However the cost savings are likely to be offset by cost increases elsewhere. Therefore to achieve significant cost savings, which would promote selection of a new or novel WGCU technology over an amine system, a WGCU system should be a simple, direct (one or two step) process which combines many of the steps listed above.

Table 1

Warm Gas Cleanup (WGCU) Comparison

GAS CLEANUP SYSTEM	WGCU	Technical Feasibility	Estimated TIC	O&M								Remarks
				CO_2 Slip %	Stm.	Adsorbent	PWR	N_2	Syn gas	Solvent Cats & Chems	Total O&M	
MDEA	N	Proven	Base	85	Base	NA	Base	NA	Base	MDEA Base	Base	Baseline/Current design
RTI Membrane Process	N	R&D	1.15xBase	100	NR	Base RVS	> Base	yes	> Base	Memb. > Base	> Base	Uses a Membrane at 80°F & passes H_2 – Separation difficult.
Global Energy Proposed Process	Y	R&D ++	1.4xBase	100	(rgn heat) > Base	8x Base	> Base	yes	> Base	PSA Mol-sieve > Base	> Base	PSA needs verification & development. Adsorbent attrition.
Rectisol	N	Proven	1.5xBase	10-90	> Base	NA	> Base	yes	Base	MEOH > Base	> Base	Limited to H_2S removal. Requires Refrigeration
SCOHS Plus (1)	N	Early R&D	0.8xBase	100	(rgn heat) > Base	Car-bon > Base	> Base	yes	> Base	O_2 > Base neg.	> Base	Temp.<300°F. H_2S removal limited. COS not tested.
Iron Oxide	Y	Pilot/ Demo	>Base	100	(rgn heat) > Base	Iron > Base	> Base	yes	> Base	O_2 > Base neg.	> Base	Limited sulfur recovery and regeneration testing. Lock hoppers required.

1- Process steps – Gas cooling - COS conversion – SCOHS – PSA (NH_3, and trace element removal) – Syngas Heating – Regeneration – Sulfur condenser – Compression for SCOHS and PSA regeneration gas.

6.0 Summary

A typical sulfur removal system for Global Energy gasification technology includes Cl removal, COS hydrolysis, H_2S removal (AGR), SWS, SRU, TGTU, and reheating. It currently excludes trace metal removal such as mercury. In general amine systems are very cost effective for IGCC. The potential savings in plant capital cost for a future IGCC with an advanced gas turbine is less than 10 MM$. Physical solvents are required to reach low sulfur levels for catalytic processes and fuel cells are significantly more expensive, thereby providing more margin for new system development. The challenge is to find a process which will be simple (and cost effective) while achieving all the process requirements. SCOHS has the potential to meet these requirements.

SCOHS operates at a slightly lower temperature than specified for WGCU, and therefore was excluded from this WGCU comparison. Also, several additional subsystems are required to make SCOHS a substitute for the amine based sulfur removal system. These sub-systems are: pre-cooling to 225^{o}F, chloride removal, post reactor sulfur removal, trace element and ammonia removal, sour water stripping, syngas re-heating and moisturization, and regeneration tail gas cleanup. This report also discusses the research needs and impediments to commercialization such as: simultaneous COS hydrolysis or reaction to sulfur; controlled air injection without runaway reaction during and after sulfur removal; higher temperature operation to avoid water or sulfur condensation; regeneration testing, and regeneration at lower temperatures (<650^{o}F). If testing and development are successful, this system should be less costly than an amine based system and achieve lower emissions.

Attachment A
Technical Information (References)

1. Gupta P. R., Krishnam, N. G. and. Cicero, D. C., “Gaseous Contaminant Control for IGCC Applications”, DOE Contract DE- AC26-99FT40675

2. Nexant, Inc., RTI Evaluation Report, 2001, personal communication from S. S. Tam.

3. Rectisol Brochure by Lotepro. June, 1976

4. Unknown, "Development of a Hot Gas Desulfurization Process"

5. Kimura, H., "Test Results of Hot Gas Clean-up Facility for 200t/d Entrained Flow Gasification Pilot Plant"

6. NETL Web site on SCOHS, contact todd.gardner@netl.doe.gov

7. Parekh, R., “Handbook of Gasifiers and Gas Treatment Systems, p. 3A.1, WD-TR-82/008-010, September 1982.

8. Westmoreland, P. R., and Harrison, D. P., “Evaluation of Candidate Solids for High Temperature Desulfurization of Low-BTU Gases”, Environmental Science and Technology, vol. 10, 659 (1976).

9. Woods, M. C., Leese, K. E., Gangwal, S. K., Harrison, D. P., and Jothimurugesan, K., “Reaction Kinetics and Simulation Models for Novel High-Temperature Desulfurization Sorbents”, p. 5-31, DOE/MC/24160-2671, February 1989.

10. U.S. Patent 5,711,926, describes a "Pressure Swing Adsorption System for Ammonia Synthesis", January, 1998.

11. Turk and Gupta, “Development and Experimental Results on RVS-1 Desulfurization Sorbent”, March 2001.

12. Kohl, A. L., and Riesenfeld, F. C., “Gas Purification”, 4th ed., Gulf Publishing Co., chapter 8, 1985.

Appendix J - Subtask 1.9

Availability Analysis

Appendix J (Subtask 1.9)
Availability Analysis

Executive Summary

The common measures of financial performance, such as return on investment (ROI), net present value (NPV), and payback period, all are dependent on the project cash flow, and the cash flow is dependent upon the annual production. Although the design capacity is the major factor influencing the annual production, other factors that influence it include scheduled maintenance, forced outages, equipment reliability, and redundancy. These other factors must be considered in order to develop a meaningful financial analysis. Thus, an availability analysis that considers all of the above factors must be performed to predict the annual production rates. Based on these annual production rates, appropriate annual revenue streams can be developed for the financial analysis.

Availability analyses were performed for all the Task 1 IGCC power plant designs to account for forced and scheduled outages to determine expected annual revenue and expense cash flows. Based on these cash flows, financial analyses were performed to evaluate the comparative economics of the various plant configurations and alternate design options.

The availability analysis showed that there could be significant differences in the capacity factor (availability) of a plant depending upon the amount of spare equipment or parallel trains that are present. Sparing is most effective in increasing the overall plant availability when those portions of the plant with the lowest on-stream factors are replicated. Although the Subtask 1.3 Petroleum Coke IGCC Coproduction Plant has a design capacity of 5,399 TPD of dry coke, it could have annual average coke capacities as low as 3,973 TPD or as high as 4,814 TPD depending upon the amount of replicated equipment (capacity factors between 73.6% and 89.2%).

These availability analyses showed the importance of designing plants and equipment that have high on-stream factors and/or require low maintenance (short or infrequent scheduled outages), and sparing or replicating those portions which have low on-stream factors and/or high maintenance (long or frequent scheduled outages).

Attachment A, Availability Nomenclature, contains definitions of availability related terms as proposed by the Gasification Technology Council. This table is supplemented with additional terms as used in this study.

Appendix J (Subtask 1.9)
Availability Analysis

The common measures of financial performance, such as return on investment (ROI), net present value (NPV), and payback period, all are dependent on the project cash flow. The net cash flow is the sum of all project revenues and expenses. Depending upon the detail of the financial analysis, the cash flow streams usually are computed on annual or quarterly bases. For most projects, the net cash flow is negative in the early years during construction and only turns positive when the project starts generating revenues by producing saleable products. However, a plant is generating revenue only when it is operating and not when it is shut down for forced outages, scheduled maintenance, or repairs. Therefore, the yearly production (total annual production) is a key parameter in determining the financial performance of a project.

Although the design capacity is the major factor influencing the annual production, other factors that influence it include scheduled maintenance, forced outages, equipment reliability, and redundancy. This appendix describes the results of the availability analyses that were conducted to calculate the annual average production rates (capacity factors) for the various cases. The calculations are based on the availability data for the individual plant sections (as shown in Table I) that were obtained at the Wabash River Repowering Project during the demonstration period. This information was then adjusted, if necessary, and used for the basis of the calculations for the specific plant configurations. Based on published mathematical formulae that account for parallel trains, spare equipment, equipment reliability, and scheduled maintenance, average annual production rates were calculated. Thus, these calculations allowed the effects of various train and equipment sparing configurations on the annual production rates to be examined.

In a subsequent financial analysis, these production rates were then used as the basis for calculating the annual revenue streams. These financial analyses and their results are not described in the appendix, but are discussed in the main portion of this report and in several of the individual subtask appendices.

Attachment A, Availability Nomenclature, contains definitions of availability related terms as proposed by the Gasification Technology Council. This table is supplemented with additional terms as used in this study.

1.0 Availability Analysis Basis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[1] This information is summarized in Table 1. During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After three adjustments, this data was used to estimate the availability of the Task 1 coal and petroleum coke IGCC plant designs. The first adjustment increased the availability of the air separation unit (ASU) from the observed availability of 96.32% to the industry average availability of 98%. The second adjustment was to improve the availability of the first gasification stage by negating the impact of a slag tap plugging problem caused by an unexpected change in the coal blend to the gasifier. For the Subtask 1.2 and 1.3 plants, this adjustment is justified since a dedicated petroleum coke plant would be very unlikely to experience this problem. The third adjustment eliminated a short outage that was caused by a service interuption in the water treatment facility because sufficient treated water storage will be available to handle this type of outage.

Based on the reported Wabash River data, availability analyses were calculated using the EPRI recommended procedure.[1] This procedure calculates availabilities based only on two plant states, operating at design capacity or not operating. For a single train plant with all the units in a series configuration (1.e.; no redundancy), the overall plant availability simply is the product of the availability of all the individual unit availabilities. For multiple trains (or for plant sections with spare units), the EPRI report presents mathematical formulas based on a probabilistic approach for predicting the availability of all trains or of 1 of 2, 2 of 3, 1 of 3, etc. Appropriate combinations of these mathematical formulae are used to represent plants with some portions containing multiple trains or spare equipment and other portions being single trains.

Since the objective of this availability study is to determine the projected annual revenue stream, this study does not differentiate between forced and scheduled outages. In other words, it is immaterial whether the plant is off line because of a forced outage as the result of an equipment malfunction or whether it is off line because of a scheduled outage for normal maintenance or refractory replacement. Consequently, the annual availabilities reported in this study probably will be different than those studies which do not consider forced and scheduled outages in such a rigorous manner.

2.0 Use of Natural Gas

To improve the yearly power output from single train gasification plants, backup natural gas is used to fire the gas turbine to make power when syngas is unavailable. Thus, for most of the year power is made from the lower cost coal, but for those times when the syngas generation portion of the plant is unavailable and the economics are favorable, power can be produced from higher priced natural gas. Multiple train power plants can be operated in a similar manner when insufficient syngas is available to fully load all the gas turbines.

The situation with the Subtask 1.2 and 1.3 petroleum coke coproduction plants is somewhat different. The gasification trains in these plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to fully fire one combustion turbine. Thus, in this situation, natural gas is used to supplement the syngas and fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption in the plant also is reduced when one gasification train is not operating by its internal power consumption and that of one air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

[1] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA 94304, August 1985.

In the less frequent situation when only one syngas train is operating and only one combustion turbine is operable, backup natural gas also is used to fully load the available gas turbine and supply the design hydrogen and steam demands. In this situation, the export power produced by the plant is about half the design rate.

In the least likely situation when both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire the gas turbine and produce export electric power from both the combustion turbine and the steam turbine. In this case, the amount of export power will be greater than that of the design capacity of the gas turbine because the reduced internal power loads are more than covered by the steam turbine.

For the Subtask 1.2 and 1.3 Petroleum Coke IGCC Coproduction Plants, the average daily natural gas rates which were calculated as part of the availability analysis given in Table 3. For the Subtask 1.4, 1.5 and 1.6 power plants, the average daily natural gas rates are given in Tables 5 and 7. Natural gas usage during startup and during maintenance operations, such as for curing refractory, are not considered in the availability analysis calculations, but are included in the operating and maintenance costs during the financial analysis.

3.0 The Subtask 1.2 and 1.3 Petroleum Coke IGCC Coproduction Plants

The design for the Subtask 1.2 plant, the non-optimized Petroleum Coke IGCC Coproduction Plant, is based on the Wabash River Plant design with only those modifications required to satisfy the new design criteria associated with the:

- Location change to the U. S. Gulf Coast,
- Feedstock change from coal to petroleum coke,
- Larger plant size,
- Coproduction of hydrogen for the adjacent petroleum refinery,
- Coproduction of steam for the adjacent petroleum refinery,
- Addition of spare equipment to provide highly reliable coproduct production, and
- Elimination of redundant equipment in Subtask 1.3 only.

As a result of this redesign effort, the non-optimized plant contains three parallel syngas generation, cleanup, hydrogen production, and steam generation trains; each with the capacity to produce 50% of design output (3x50%) as shown at the top of Table 2. The spare gasifier vessel (that is present in the Wabash River design) was removed from each train. Two combustion turbines (2x50%) and a single steam turbine (1x100%) generate the electric power. In the rare situation when only a single gasification train is operable, with backup natural gas firing it will have sufficient capacity to satisfy the refinery hydrogen and steam demands at the expense of electric power production. Based on the Wabash River plant data, each train will require scheduled outages amounting to 17.0% of the time for routine maintenance, repair, and periodic replacement of the gasifier refractory (62 days/year)

The bottom of Table 2 shows that, two gasifiers should be available 77.41% of the time, and only one should be available 99.20% of the time. The resulting equivalent syngas availability will be 92.07% (i.e.; annual syngas production expressed as a fraction of the design capacity on an annual basis). Since only one operable train is required to satisfy the

Table 1
Wabash River Plant Availability
Data During the Demonstration Period[2]

Plant Section	Observed Availability	Adjusted Availability	Comments
SYNGAS GENERATION AREA			
Air Separation Unit	96.32%	98.00%	See note 1
Coke Handling	100.00%	100.00%	
Slurry Preparation	99.96%	99.96%	
Rod Mill	100.00%	100.00%	
Slurry Tank	99.96%	99.96%	
Gasification (through HTHRU)	83.42%	86.40%	See notes 3 and 4
First Stage	87.06%	90.16%	See note 2
Second Stage	97.82%	97.82%	
Raw Syngas Conditioning	100.00%	100.00%	
HTHRU	97.96%	97.95%	
Slag Handling	99.15%	99.15%	
Dry Particulate Removal	98.03%	NA	See note 5
Chloride Scrubbing System	99.87%	NA	See note 5
LTHR / AGR	99.62%	99.62%	
Low Temperature Heat Recovery (LTHR)	99.90%	99.90%	
Syngas Moistureization	100.00%	100.00%	
Acid Gas Removal	99.72%	99.72%	
Sulfur Recovery Unit	99.94%	99.94%	
POWER BLOCK			
Combustion Turbine	98.19%	98.19%	
Heat Recovery Steam Generator	97.40%	97.40%	
Water Treatment Facility	99.83%	100.00%	See note 5
Steam Turbine	99.88%	99.88%	

Notes:
1. Based on industry average value which allows for a derime outage every second operating year.
2. Removed slag tap plugging that resulted from an unexpected change in coal blend to the first stage gasifier in January 1999.
3. Expected operating improvements are projected to boost the availability of the Gasification (thru HTRU) to 93.0%. This compares the recent plant experience on petroleum coke for the 2000 calendar year where the availability was 94.5%.
4. For the Observed Availability, the 83.42% of the Gasification (thru HTRU) is the product of the following four items (83.42% = 87.06% * 97.82% * 100% * 97.96%).
5. The dry particulate removal system and the wet chloride scrubbing system used at Wabash River are replaced by a hybrid dry cyclone / wet scrubber particulate removal system in the Subtask 1.3 cases. This system consists of a hot cyclone, which removes most of the particulates from the syngas, followed by a wet scrubber column. Except in the 1.3 Next Plant case where the particulate removal downstream of the cyclone is by a dry filter system (as used at Wabash River)
6. Assumes water storage can compensate for an unscheduled outage.

[2] Global Energy, Inc. "Wabash River Coal Gasification Repowering Project – Final Report," September 2000.

Table 2
Subtask 1.2 and Subtask 1.3
Plant Configurations and Availabilities

Case Identification Case Description	**Task 1.2**	**Task 1.3 Base**	**Task 1.3 Minimum Cost**	**Task 1.3 Spare Train**	**Task 1.3 Next Plant**
Plant Section	Number of Trains and Section Capacity (Note 1)				
ASU	2x50%	2x50%	2x50%	2x50%	2x50%
Coke Handling	1x100%	1x100%	1x100%	1x100%	1x100%
Slurry Prep (note 3)	**3x50%**	2x60%	2x60%	2x60%	2x60%
Slurry Feed	**3x50%**	2x50%	2x50%	**3x50%**	**3x50%**
Gasification (though HTHRU) (note 4)	**3x50%**	**2x50%**	**2x50%**	**3x50%**	**3x50%**
Slag Handling	1x100%	1x100%	1x100%	1x100%	1x100%
One-Stage Dry Particulate Removal	**3x(2x30%)**				
Two-Stage Dry Particulate Removal					**3x50%**
Chloride Scrubbing System	**3x50**				**2x50%**
Wet Particulate Removal		**2x50%**	**2x50%**	**3x50%**	
LTHR/AGR	**3x50%**	2x50%	2x50%	2x50%	2x50%
SRU	**3x50%**	2x50%	2x50%	2x50%	2x50%
Hydrogen	**3x50%**	2x50%	2x50%	2x50%	2x50%
Combustion Turbine	2x50%	2x50%	2x50%	2x50%	2x50%
Steam Turbine	1x100%	1x100%	1x100%	1x100%	1x100%
Scheduled Outages per Train	**16.99%**	**7.67%**	**15.34%**	**15.34%**	**15.34%**
Spare Gasifier Vessels (1 per train)	**No**	**Yes**	**No**	**No**	**No**
Possible Syngas Availability, % (note 5)					
From Two Gasifiers (@100% rate)	84.74%	67.69%	55.42%	86.41%	86.85%
From Only One Gasifier (@50% rate)	99.39%	98.00%	96.73%	99.58%	99.63%
Equivalent Availability (note 6)	92.07%	82.85%	76.08%	93.00%	93.24%
Net Syngas and Power Availability, %					
From Two Gasifiers (@100% rate)	77.41%	61.84%	50.63%	78.94%	79.34%
From Only One Gasifier (@50% rate)	99.20%	97.81%	96.55%	99.39%	99.81%
Equivalent Availability (note 6)	88.31%	79.83%	73.59%	89.17%	89.39%
Equivalent Power Availability (notes 6 & 7)	94.58%	93.34%	92.35%	94.72%	94.61%
Hydrogen and Steam Availability, % (note 2)					
Equivalent **Steam** Availability (note 6)	99.20%	97.81%	96.55%	99.39%	99.44%
Equivalent **Hydrogen** Availability (notes 6 & 8)	99.20%	96.84%	95.58%	98.40%	98.45%

Notes:
1. Capacity percentages are based on the total plant design capacity.
2. Based on an average hydrogen plant availability of 99.0%.
3. For the Subtask 1.3 Base and Minimum Cost Cases, the ball mills are (2x60%), and for the Subtask 1.3 Spare Train Case, they are (3x60%).
4. The Subtask 1.3 Base Case has a spare gasifier vessel in each train.
5. This is the clean syngas availability without any downstream constraints on consumption or use of the syngas; e.g., when exporting syngas to a pipline.
6. Equivalent availability is the average annual capacity expressed as a fraction of the design capacity.
7. Assumes supplemental firing with natural gas to make maximum use of the combustion and steam turbines. For the 1.3 Next Plant case, gas firing produces the same steam power as the other 1.3 cases, but the Next Plant case has a larger steam turbine so the percentage power production is slightly lower, but the total power production is greater.
8. Adding a third 50% hydrogen plant will increase the 100% hydrogen availability to about that of the syngas availability from one gasifier.

refinery hydrogen and steam demands, these items will have an equivalent availability 99.20%, essentially the same as that when one of the two gasifier trains is operating.

The Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 88.31% (i.e., power production from syngas expressed as a fraction of the design capacity on an annual basis). On this basis, the plant will have an average daily dry coke consumption of 4,635 TPD dry basis or 88.31% of the design coke consumption of 5,249 TPD.

The Subtask 1.3 Base Case for the Optimized Petroleum Coke IGCC Coproduction Plant, has been reduced to a two train gasification plant; each with the capacity to produce 50% of design output (2x50%) as shown in Table 2. However, a spare gasifier vessel has been added to each train to match the configuration of the Wabash River plant. When one gasifier vessel needs refractory replacement, the additional vessel can be placed in service, and the refractory replacement can be done while the train is operating with the previously spare vessel in service. This significantly reduces the scheduled maintenance time per train from 16.99% to 7.67% (62 to 28 days per year).

The dry char filter particulate removal system that is used at Wabash River and in the Subtask 1.2 design was replaced by a hybrid dry cyclone / wet scrubber particulate removal system. This new system is a two-step system that consists of a cyclone, which removes most of the particulates from the syngas, followed by a wet scrubbing system. The wet scrubbing system performs the dual purpose of removing both the particulates and chlorides from the syngas in a single step; thus eliminating the need for a separate chloride scrubbing system. The availability of this new system is estimated to be 99.0% compared to the 98.03% availability of the Wabash River dry char filters and the 99.87% availability of the chloride scrubbing system, excluding scheduled outages.

As shown in Table 2, the syngas availability from both gasifier trains of the Subtask 1.3 Base Case for the Optimized Petroleum Coke IGCC Coproduction Plant should be 61.84, and from only one gasifier train it should be 97.81%. The resulting equivalent syngas availability will be 82.85%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 97.81%, essentially the same as that of a single gasifier train. The hydrogen availability will be only 96.84% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.2% lower than that of the Subtask 1.2 case. Because of the lower gasification train availability, significantly more backup natural gas is consumed to produce power. The steam availability is about 1.4% lower; and the hydrogen availability is about 2.4% lower. Although the Subtask 1.3 Base Case plant has lower availabilities, it has a significantly lower cost that should result in a higher Return on Investment (ROI).

The Subtask 1.3 Base Case Optimized Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 79.83%. On this basis, the plant will have an average daily dry coke capacity of 4,310 TPD dry basis or 79.83% of the design coke consumption of 5,399 TPD. This is an average of 325 TPD less coke than that of the Subtask 1.2 non-optimized plant.

The Subtask 1.3 Minimum Cost Petroleum Coke IGCC Coproduction Plant is the same as the Subtask 1.3 Base Case except that the spare gasifier vessel in each gasification train has been removed. Thus, when a gasifier vessel needs refractory replacement, the entire train is shut down while the refractory is being replaced. This significantly increases the scheduled outage time per train from 7.67% for the base case to 15.34% for this case.

The syngas availability from both gasifier trains of the Subtask 1.3 Minimum Cost should be 50.63%, and from only one gasifier train it should be 96.55%. The resulting equivalent syngas availability will be 76.08%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 96.55%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 95.58% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.0% lower than that of the Subtask 1.3 base case because more backup natural gas is used to make power. The steam availability is about 1.3% lower; and the hydrogen availability is about 1.3% lower. Although the Subtask 1.3 Minimum Cost plant has lower availabilities and a lower cost, it could result in a higher ROI.

The Subtask 1.3 Minimum Cost Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 73.59%. On this basis, the plant will have an average daily dry coke capacity of 3,973 TPD dry basis or 73.59% of the design coke consumption of 5,399 TPD. This is an average of 337 TPD less coke than that of the Subtask 1.3 Base Case plant.

The Subtask 1.3 Spare Gasification Train Petroleum Coke IGCC Coproduction Plant is the same as the Subtask 1.3 Minimum Cost case except that a third parallel gasification train (3x50%) has been added wherever solids are being processed, from the slurry pumps through the wet scrubber. Thus, when a gasifier vessel needs refractory replacement that entire train is shut down while the refractory is being replaced, and the spare train that was on standby is placed in service. This scheduled maintenance time per train for this case is 15.34%, the same as that for the Subtask 1.3 Minimum Cost Case.

The syngas availability from two gasifier trains of the Subtask 1.3 Spare Train plant should be 78.94%, and from only one gasifier train it should be 99.39%. The resulting equivalent syngas availability will be 93.00%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 99.39%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 98.40% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.4% higher than that of the Subtask 1.3 base case even though it uses less backup natural gas. The steam availability is about 1.6% higher; and the hydrogen availability is about 1.6% higher. Although the Subtask 1.3 Spare Train plant has higher availabilities, it has a higher cost that could result in a higher ROI.

The Subtask 1.3 Spare Train Petroleum Coke IGCC Coproduction Plant will have an equivalent syngas power generation capacity of 89.17%. On this basis, the plant will have an average daily dry coke capacity of 4,814 TPD dry basis or 89.17% of the design coke consumption of 5,399 TPD. This is an average of 504 TPD more coke than that of the Subtask 1.3 Base Case.

The Subtask 1.3 Next Plant Petroleum Coke IGCC Coproduction Plant is very similar to the Subtask 1.3 Spare Train case except that it contains a two-stage dry particulate removal system (cyclones and a dry char filters) rather than combination dry and wet system (cyclones followed by a wet scrubber). Thus, no solids now enter the wet scrubber, and its main purpose is to remove chlorides and other water-soluble impurities from the syngas. Consequently, it should be highly reliable, and only two wet scrubber columns (2x50%) are used rather that the three in the Spare Train case. Thus, in the Next Plant case, the spare gasification train runs from the slurry pumps through the dry char filters. As is the case in the Spare Train case, when a gasifier vessel needs refractory replacement, that entire train is shut down while the refractory is being replaced, and the spare train that was on standby is placed in service. This scheduled maintenance time per train for this case is 15.34%, the same as that for the Subtask 1.3 Minimum Cost and Spare Train Cases.

The syngas availability from two gasifier trains of the Subtask 1.3 Next Plant should be 79.34%, and from only one gasifier train it should be 99.63%. The resulting equivalent syngas availability will be 93.24%. Since in this case also, only one operable train with backup natural gas firing is required to satisfy the refinery steam demand, it will have an equivalent availability 99.44%, essentially the same as that of a single gasifier train. However, the hydrogen availability will be only 98.45% because it will be reduced by the availability of the hydrogen production facilities. The equivalent power availability for this case is about 1.3% higher than that of the Subtask 1.3 base case even though it uses less backup natural gas. The steam availability is about 1.6% higher; and the hydrogen availability is about 1.6% higher.

The Subtask 1.3 Next Plant will have an equivalent syngas power generation capacity of 89.39%. On this basis, the plant will have an average daily dry coke capacity of 4,842 TPD dry basis or 89.38% of the design coke consumption of 5,417 TPD. This is an average of 534 TPD more coke than that of the Subtask 1.3 Base Case.

Table 3 compares the design (stream day) and average daily (calendar day) feed and product rates for the Subtask 1.2 case and the four Subtask 1.3 cases. Two design rates are shown for some Subtask 1.3 feed and products. The first set of rates is for the Subtask 1.3 Base Case, Minimum Cost Case, and the Spare Train Case. The second set of rates is the Subtask 1.3 Next Plant. These rates are slightly larger because the two-stage dry particulate removal system slightly increases the gasifier capacity.

As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and fuel gas product rates, and for the coke and flux feed rates. This is because these design rates are based on two trains running simultaneously. For the Subtask 1.2 and Subtask 1.3 Spare Train cases, the calendar day rates are closest to the design rates because these cases have two operating and one spare train in the least reliable areas of the plant, and only two of them need to be running simultaneously to make the design rates. For all cases, the calendar day steam and hydrogen rates are a lot closer to the design rates since only one gasification train has to be operating for the plant to produce the design product rates.

The daily average natural gas rates shown in Table 3 are the lowest for the three cases where there are three parallel gasification trains, Subtask 1.2, the Subtask 1.3 Spare Train case, and the Subtask 1.3 Next Plant case. This is because these cases have the highest availability of two trains. Thus, they, require the least amount of backup natural gas firing. The availability of the gasification trains in the Subtask 1.3 Base Case is higher than in the Subtask 1.3 Minimum Cost case because the former has a spare gasification reactor in each train. Consequently, the Base Case requires less natural gas usage than the Minimum Cost case.

Figure 1 compares the design and daily average coke consumptions for the Subtask 1.2 plant and for the four Subtask 1.3 cases. In all cases, the average daily coke consumption is significantly less than the design capacity. This difference is the least for the Subtask 1.3 Spare Train Case where it is only 585 TPD of dry coke less than the design capacity of 5,399 TPD, and it is the greatest for the Subtask 1.3 Minimum Cost Case where it is 1,426 TPD less. For the Subtask 1.3 Base Case, the average daily dry coke consumption is 1,090 TPD less than the design rate of 5,399 TPD.

Figure 2 shows the amount of time that various sections of the plant are operating. For Subtask 1.2,

- two gasification trains and two combustion turbines (code: 2Gs & 2 CTs) are operating about 77.4% of the time;
- only 1 gasification train and 2 combustion turbines (code: 1 G & 2 CTs) are operating about 13.4% of the time;
- only 1 gasification train and 1 combustion turbine (code: 1 G & 1 CT) are operating about 8.4% of the time; and
- only 1 combustion turbine (Code: 0Gs & 1CT) are operating about 0.6% of the time.

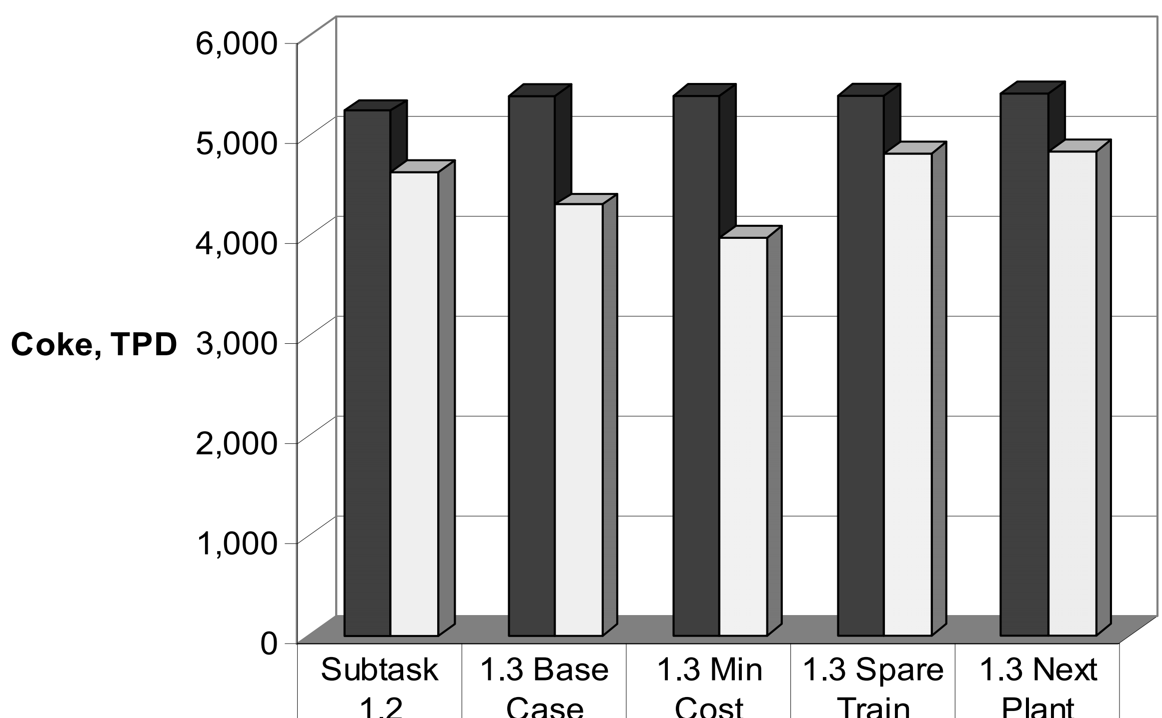
This shows that for about 22.4% of the time, one or more gas turbines are using natural gas as a backup fuel because an insufficient amount of syngas is available. For the Subtask 1.3 Base Case, backup gas firing is used almost 38% of the time. For the Subtask 1.3 Minimum Cost case, backup gas firing is used about 49.2% of the time. The Subtask 1.3 Spare Train Case uses backup natural gas firing for about 20.9% of the time because the individual gasification trains have the highest availability. All four bars have the same height of 99.8%, which is the availability of one of the two combustion turbines.

Figure 3 shows the equivalent power availability as a function of the design rate produced by each mode of operation for the four cases. The height of each bar represents the annual equivalent power availability of each case as shown in Table 8. The Subtask 1.3 Spare Train Case has the highest total equivalent power availability of 94.7%, and the Subtask 1.3 Minimum Cost Case has the lowest equivalent power availability of 92.35%. For the Subtask 1.3 Base Case, about 31.5% of the design power is made when natural gas is being used, and for the Subtask 1.3 Spare Train Case, only about 15.8% of the power is being made when natural gas is being fired.

Table 3
Design and Daily Average Feed and Product Rates for Subtasks 1.2 and 1.3

	Subtask 1.2		Subtask 1.3				
				Daily Average			
	Design	Daily Average	Design	Base Case	Minimum Cost Case	Spare Train	Next Plant
Product Rates							
Power, MW	395.8	374.3	460.7 / 474.0	430.0	425.4	436.4	448.4
Steam, Mlb/hr	980.0	972.2	980.0	958.6	946.2	974.1	974.6
Hydrogen, MMscfd	79.4	78.8	80.0	77.5	76.5	78.7	78.8
Sulfur, TPD	367.0	324.1	371.8 / 373.4	296.8	273.6	331.5	333.8
Slag, TPD	190.0	167.8	194.5 / 195.1	155.3	143.1	173.4	174.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0	0
Feed Rates							
Coke, TPD dry	5,249	4,635	5,399 / 5,417	4,310	3,973	4,814	4,842
Flux, TPD	107.0	94.5	110.2 / 110.6	88.0	81.1	98.3	98.9
Natural Gas, MMBtu/d	0	10,099	0	20,000	26,977	9,303	9,059

Figure 1
Design and Daily Average Coke Consumptions



	Subtask 1.2	1.3 Base Case	1.3 Min Cost	1.3 Spare Train	1.3 Next Plant
Design	5,249	5,399	5,399	5,399	5,417
Average	4,635	4,310	3,973	4,814	4,842

Figure 2
Equipment Availability by Time

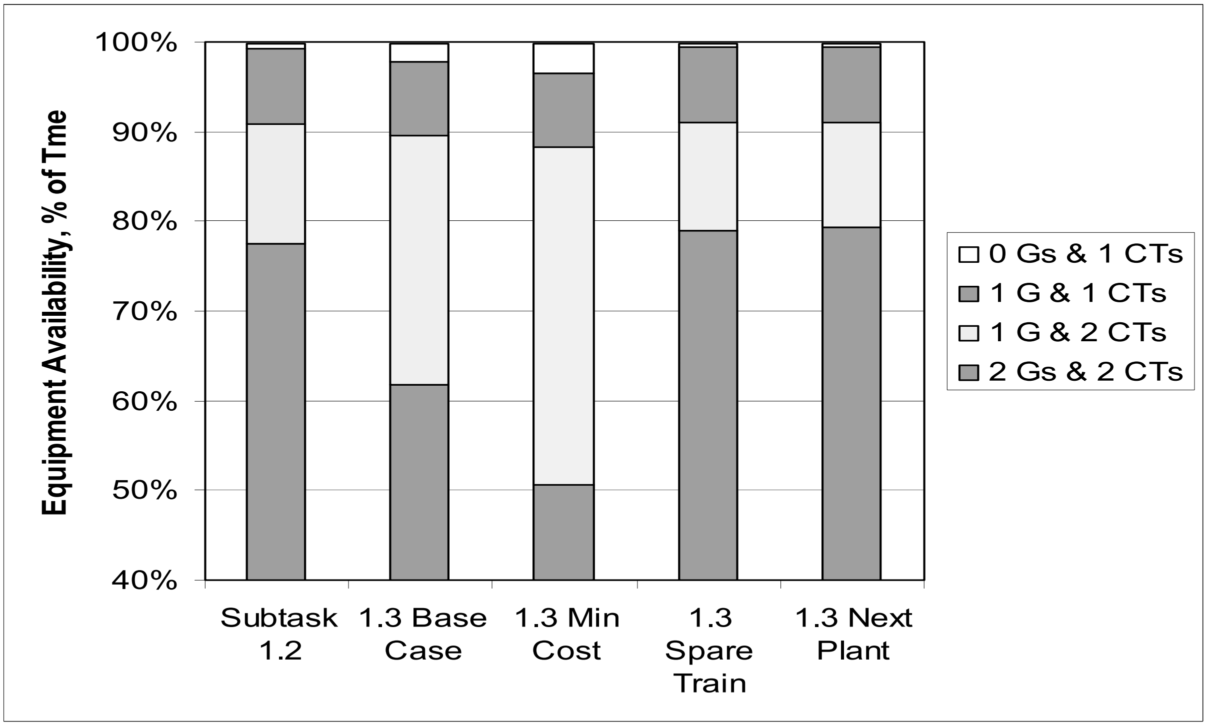
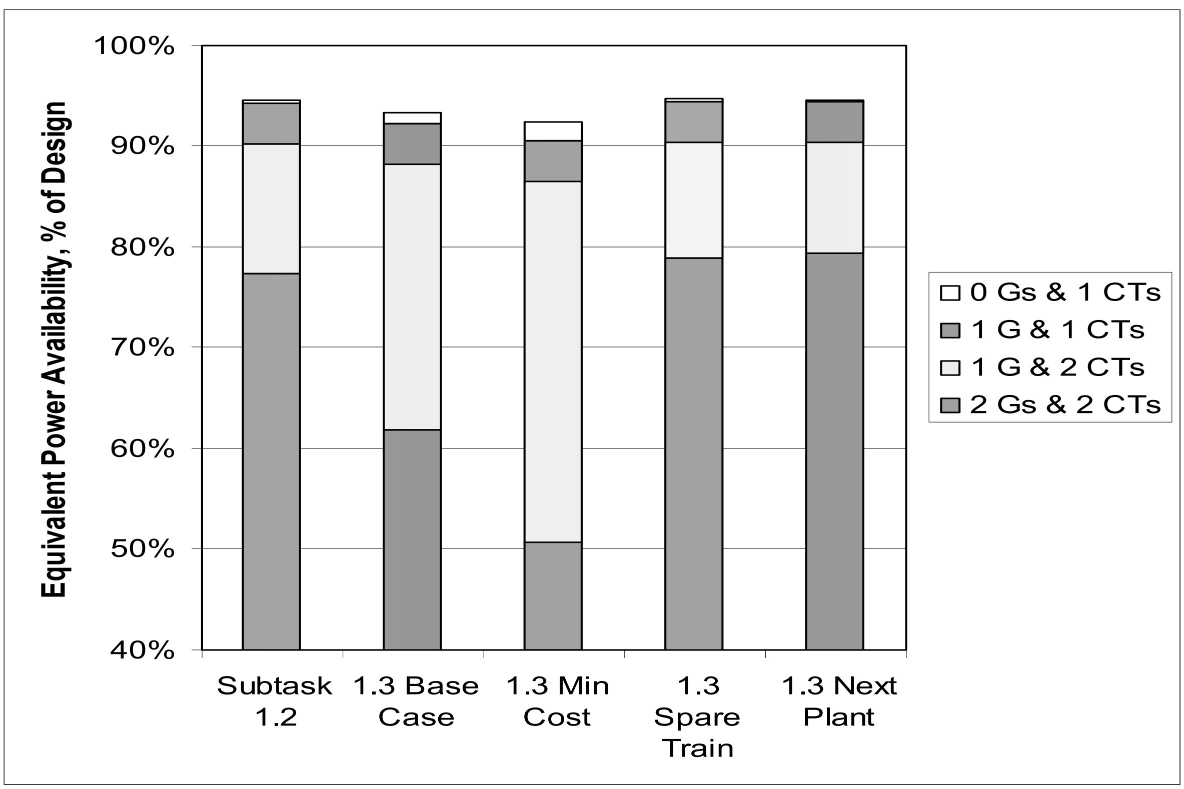


Figure 3
Equivalent Power Availability by Production



4.0 The Subtask 1.1, 1.4 and 1.5 IGCC Power Plants

The Subtask 1.1, 1.4 and 1.5 plants are single-train IGCC Power Plants. The Subtask 1.5B plant is a coke fueled facility, and the other three are coal fueled facilities. All four plants produce slag and sulfur as byproducts. The Subtask 1.5B coke fueled plant requires flux as an additional feedstock that is mixed with the coke.

The Subtask 1.4 and 1.5 plants are designed to use supplemental natural gas to fire the gas turbines when syngas is unavailable. The Subtask 1.1 Wabash River Greenfield Plant was not configured to use backup natural gas for power production until the summer of 2001.

Table 4 defines the configuration of the four plants. The Subtask 1.1 Wabash River Greenfield Plant essentially has the same configuration as the Wabash River Repowering Project. It is a single train plant except that the dry particulate removal system consists of two trains, each with a capacity to filter 60% of the total syngas (2x60%), and it has a spare gasification reactor vessel in place, but unconnected. Thus, when the gasifier vessel needs refractory replacement that entire train is shut down and the piping is rearranged so that the spare vessel now is in service, and refractory replacement can be done while the other vessel is in operation. When the maintenance work has been completed, the off-line vessel now becomes the standby vessel. This average annual scheduled maintenance time for this case is 11.67%.

The Subtask 1.1 plant is expected to have an annual syngas availability of 79.00% and an annual equivalent power availability from syngas of 75.46%. Using backup natural gas when syngas is not available could increase the annual power production, but this option is not available for this case because it was not included in the Wabash River Repowering Project.

Table 5 shows the design and daily average feed and product rates for the Subtask 1.1 Wabash River Greenfield Plant. The plant is designed to process 2,259 TPD of dry coal to generate 269.3 MW of export power. However, because of scheduled and forced outages, it will have an annual average dry coal consumption of 1,705 TPD and produce 203.2 MW of export power.

The Subtask 1.4 Optimized Coal to Power IGCC Plant is a future plant design that is expected to be available at the end of the decade. It uses an advanced gasifier design, an advanced "H class" gas turbine, and a two-stage dry particulate removal system similar to the Subtask 1.3 Next Plant design except that the cyclone is located upstream of the high temperature heat recovery unit. This system consists of a cyclone followed by dry char filters. Because the cyclone removes about 95% of the solids before they reach the filters and of recent improvements in the design and operation of the dry char filter system itself, this system is expected to have a very high reliability.

The Subtask 1.4 Optimized Coal to Power IGCC Plant is a single train plant with the configuration shown in Table 4. It does not contain a spare gasifier vessel. When maintenance work has to be done on the gasifier, the syngas section of the plant has to be shut down. Backup natural gas can be used to fire the combustion turbines when syngas is unavailable. Because of the advanced gasifier design, the amount of time allotted for scheduled maintenance has been reduced to 6.58%.

The Subtask 1.4 plant is expected to have an annual syngas availability of 83.56% and annual equivalent power availability from syngas of 79.82% without then use of backup natural gas and 93.10% with natural gas. Figure 4 graphically shows the improvement with the use of backup natural gas.

The design and daily average feed and product rates for the Subtask 1.4 Optimized Coal to Power IGCC Plant are given in Table 5. The plant is designed to process 3,007 TPD of dry coal to generate 416.5 MW of export power. However, because of scheduled and forced outages, it will have an annual average dry coal consumption of 2,400 TPD and produce 387.8 MW of export power with the use of backup natural gas. Without the use of backup natural gas, the annual average export power would be only 332.5 MW.

The single-train Subtask 1.5A coal fueled and Subtask 1.5B coke fueled IGCC power plants are based on the Subtask 1.3 Base Case. Both plants have a spare gasification reactor vessel to minimize the downtime when the refractory has to be replaced. The particulate removal system is a two-stage system consisting of a cyclone followed by a wet scrubbing column. This two-stage system is expected to have a higher availability then the dry char filter system used in Subtasks 1.1 and 1.2 but less than that of the cyclone and dry char filter system used in Subtask 1.3 Next Plant and Subtask 1.4.

Both the Subtask 1.5 plants are expected to have an annual syngas availability of 81.86% and annual power availability from syngas of 78.19% without the use of backup natural gas. With backup natural gas the Subtask 1.5A coal plant should have an equivalent power availability of 92.90%, and the Subtask 1.5B coke plant should have an equivalent power availability of 92.47%. The difference between the two plants is that the steam turbine is larger in the coke case because the mineral matter in the coke and and flux consumes less energy, and more steam is produced. This extra steam is not produced when backup natural gas is used. Figure 4 graphically shows the improvement with the use of backup natural gas.

The design and daily average feed and product rates for the Subtask 1.5 coal and coke IGCC power plants are given in Table 5. The 1.5A coal plant is designed to process 2,335 TPD of dry coal to generate 284.6 MW of export power. However, because of scheduled and forced outages, it will have an annual average dry coal consumption of 1,826 TPD and produce 264.4 MW of export power with the use of backup natural gas. Without the use of backup natural gas, the annual average export power would be only 222.5 MW.

The 1.5B coke plant is designed to process 1,977 TPD of dry coke to generate 291.3 MW of export power. However, because of scheduled and forced outages, it will have an annual average dry coke consumption of 1,546 TPD and produce 269.9 MW of export power with the use of backup natural gas. Without the use of backup natural gas, the annual average export power would be only 227.8 MW.

Table 4
Subtask 1.1, 1.4 and 1.5
Plant Configurations and Availabilities

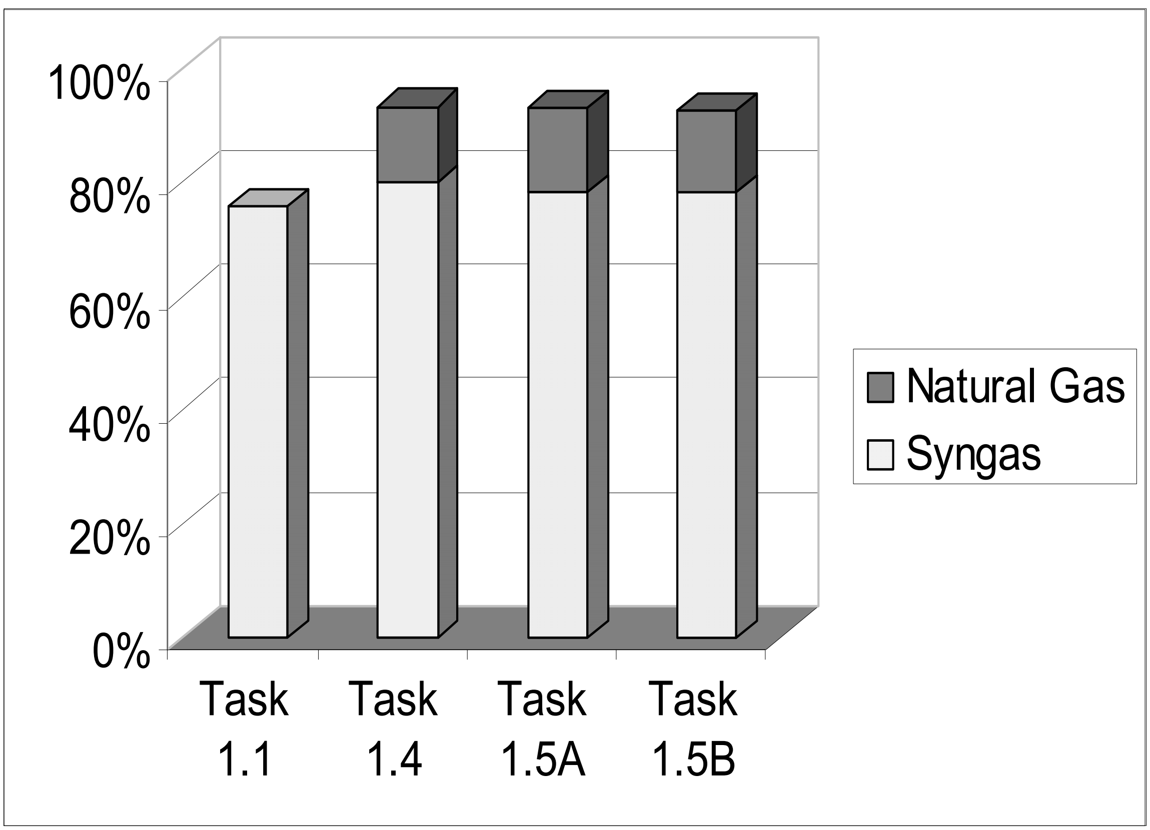
Case Identification Fuel	**Task 1.1** **Coal**	**Task 1.4** **Coal**	**Task 1.5A** **Coal**	**Task 1.5B** **Pet Coke**
Plant Section	Number of Trains and Section Capacity (Note 1)			
ASU	1x100%	1x100%	1x100%	1x100%
Coke Handling	1x100%	1x100%	1x100%	1x100%
Slurry Prep (note 3)	1x100%	1x100%	1x100%	1x100%
Slurry Feed	1x100%	1x100%	1x100%	1x100%
Gasification (though HTHRU)	1x100%	1x100%	1x100%	1x100%
Slag Handling	1x100%	1x100%	1x100%	1x100%
One-Stage Dry Particulate Removal	**2x60%**			
Two-Stage Dry Particulate Removal		**1x100%**		
Wet Particulate Removal			**1x100%**	**1x100%**
Chloride Scrubbing System	**1x100%**			
LTHR/AGR	1x100%	1x100%	1x100%	1x100%
SRU	1x100%	1x100%	1x100%	1x100%
Combustion Turbine	1x100%	1x100%	1x100%	1x100%
Steam Turbine	1x100%	1x100%	1x100%	1x100%
Scheduled Outages per Train	**11.67%**	**6.58%**	**7.67%**	**7.67%**
Spare Gasifier Vessels (1 per train)	**Yes**	**No**	**Yes**	**Yes**
Syngas Availability, % (note 2)	79.00%	83.56%	81.86%	81.86%
Net Syngas and Power Availability, %	75.46%	79.82%	78.19%	78.19%
Equivalent Power Availability (note 3)				
Without Natural Gas Backup	75.46%	79.82%	78.19%	78.19%
With Natural Gas Backup (note 3)	---	93.10%	92.90%	92.47%

Notes:
1. Capacity percentages are based on the total plant design capacity.
2. This is the clean syngas availability without any downstream constraints on consumption or use of the syngas; e.g., when exporting syngas to a pipline.
3. Equivalent availability is the average annual capacity expressed as a fraction of the design capacity.
4. Assumes supplemental firing with natural gas to make maximum use of the combustion and steam turbines.

Table 5
Design and Daily Average Feed and Product Rates for Subtasks 1.1, 1.4 and 1.5

	Subtask 1.1		Subtask 1.4		Subtask 1.5A		Subtask 1.5B	
	Design	Daily Average	Design	Daily Average	Design	Daily Average	Design	Daily Average
Product Rates								
Power, MW	269.3	203.2	416.5	387.8	284.6	264.4	291.3	269.4
Sulfur, TPD	57	43.0	76.7	61.2	60	46.9	71	55.5
Slag, TPD	356	268.6	462.0	368.7	364	284.6	136	106.3
Feed Rates								
Coal, TPD dry	2,259	1,705	3,007	2,400	2,335	1,826	---	---
Coke, TPD dry	---	---	---	---	---	---	1,977	1,546
Flux, TPD	0	0	0	0	0	0	40	31.3
Natural Gas, MMBtu/d	0	0	0	8,896	0	6,929	0	6,929

Figure 4
Equivalent Power Availabilities With and Without Backup Natural Gas for Subtasks 1.1, 1.4 and 1.5



5.0 The Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant

The Base Case of the Subtask 1.6 Nominal 1,000 MW Coal IGCC Power Plant contains three air separation units (ASUs), four gasification trains, four combustion turbines, and two steam turbines. The other portions of the plant, such as the slurry preparation, chloride scrubber, low temperature heat recovery (LTHR), COS hydrolysis, and sulfur removal, are two trains without any spare trains. However, critical pieces of equipment, normally pumps, may be spared in each train. The slurry preparation area is slightly oversized with two 60% trains and some slurry storage to accomodate short forced outages.

Table 6 shows the replication of the various plant sections for the Subtask 1.6 Base Case and an alternate case. In the Base Case, all trains are sized so that when everything is operating at the design capacity the plant will make the rated 1154.6 MW of export power from 9,266 TPD of dry coal. In the alternate case, the four gasification trains are oversized to 33.3% of the design capacity so that only three of them need to be operating to make the design export power. With this sizing, the fourth gasification train is a spare train that can be brought on line when one gasification train is unavailable either by a forced or scheduled outage. As will be shown later, this additional incremental capacity of the gasification trains to create a spare train greatly increases the power production from syngas.

Because there are three air separation units and four gasification trains in the Base Case, the availability analysis procedure used for the previous cases had to be modified for this plant. The shutdown of one ASU will not only cause the shutdown of one gasification train, but also will require the cutback of the other three trains to 88.9% of their design capacity. In order to avoid the forced capacity reduction of the three trains when one ASU is shutdown, the capacities of each ASU have to be increased to 37.5% of the total plant capacity. Thus, the total ASU capacity will be 112.5% of the total plant capacity. At the right location and under normal conditions, some over the fence oxygen sales could be possible.

In the rare situation when only one of the three 33.3% ASUs is operating, only one gasification train can be operated because insufficient oxygen is available to run two trains at a reduced capacity. This situation will occur about 0.12% of the time. However, with 37.5% ASUs, two gasification trains could be operated at 75% capacity for short periods.

The modified availability analysis for this case considered the various ASU scenarios of three, two, one or no operable ASUs and combined these cases with the various gasification train/gas turbine cases to calculate the power production both from syngas and with backup natural gas. The results are shown at the bottom of Table 6. For the Subtask 1.6 Base Case, the equivalent power availability from syngas would be 75.74%. With the use of backup natural gas, the equivalent power availability increases to 93.63%.

The equivalent power availability from syngas for the alternate case with the spare train is significantly increased to 88.05%. With the use of backup natural gas, the equivalent power availability increases to 94.85%. Figure 5 graphically compares the equivalent power productions from syngas and natural gas for these two Subtask 1.6 cases.

Because of the higher power production from syngas and the higher overall equivalent power availability, the alternate case generates a higher return on investment. This is because of a higher revenue stream from the increased power production and the lower expenses of the cheaper fuel (coal versus natural gas) overcompensate for the increased plant cost.

Table 6
Subtask 1.6 Plant Configurations and Availabilities

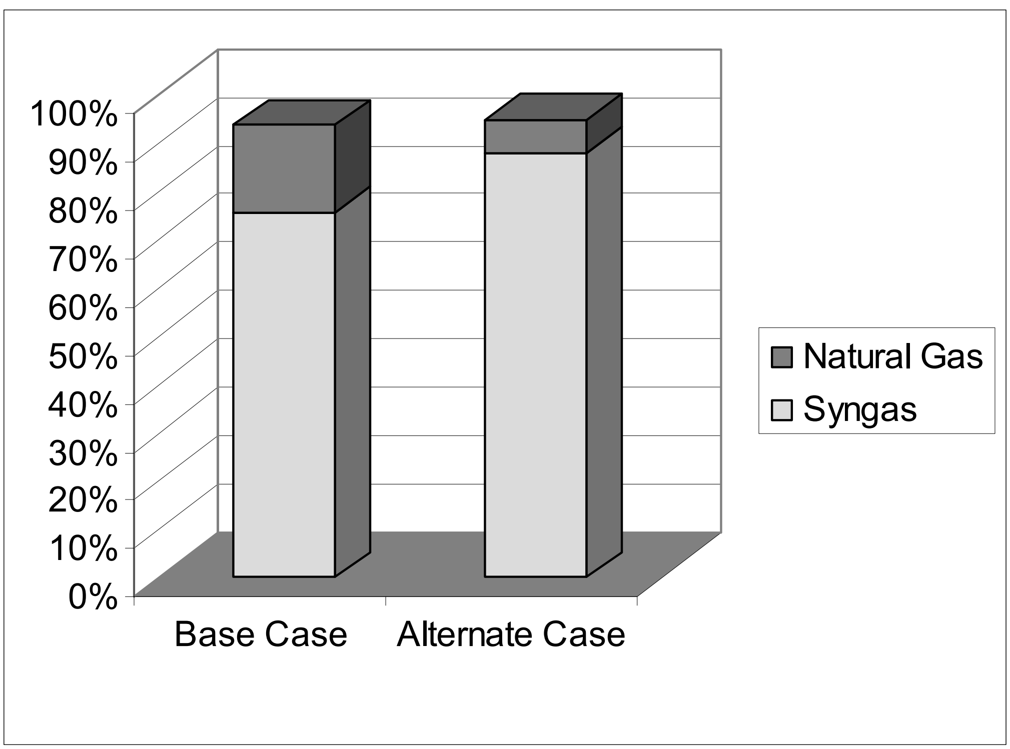
Case Identification	**Task 1.6 Base Case**	**Task 1.6 Alternate Case**
Plant Section	Number of Trains and Section Capacity	
ASU	3x33.3%	3x33.3%
Coke Handling	4X25%	4x33.3%
Slurry Prep	2x60%	2x60%
Slurry Feed	4x25%	4x33.3%
Gasification (though HTHRU)	4x25%	4x33.3%
Slag Handling	2x50%	2x50%
One-Stage Dry Particulate Removal		
Two-Stage Dry Particulate Removal	**4x25%**	**4x33.3%**
Chloride Scrubbing System	**2x50%**	**2x50%**
LTHR/AGR	2x50%	2x50%
SRU	2x50%	2x50%
Combustion Turbine	4x25%	4x25%
Steam Turbine	2x50%	2x50%
Scheduled Outages per Train	**7.67%**	**7.67%**
Spare Gasifier Vessels (1 per train)	**No**	**No**
Equivalent Power Availability (note 3)		
Without Natural Gas Backup	75.74%	88.05%
With Natural Gas Backup (note 2)	93.63%	94.85%

Notes:
1. Capacity percentages are based on the total plant design capacity.
2. Equivalent availability is the average annual capacity expressed as a fraction of the design capacity.
3. Assumes supplemental firing with natural gas to make maximum use of the combustion and steam turbines.

Table 7
Design and Daily Average Feed and Product Rates for Subtask 1.6

		Daily Average Rates			
		Base Case		Alternate Case	
	Design	w/o Gas	With Gas	w/o Gas	With Gas
Product Rates					
Power, MW	1154.6	874.5	1081.0	1,016.6	1095.1
Sulfur, TPD	236.6	179.2	179.2	208.3	208.3
Slag, TPD	1423	1077.8	1077.8	1252.9	1252.9
Feed Rates					
Coal, TPD dry	9,266	7,018	7,018	8,159	8,159
Natural Gas, MMBtu/d	0	0	34,961	0	14,338

Figure 5
Equivalent Power Availabilities With and Without Backup Natural Gas for Subtask 1.6



6.0 Summary

Availability analyses were performed for all the Task 1 IGCC power plant designs to account for forced and scheduled outages to determine expected annual revenue and expense cash flows. Based on these cash flows, financial analyses were performed to evaluate the comparative economics of the various plant configurations and alternate design options.

The availability analysis showed that there could be significant differences in the capacity factor (availability) of a plant depending upon the amount of spare equipment or parallel trains that are present. Sparing is most effective in increasing the overall plant availability when those portions of the plant with the lowest on-stream factors are replicated. Although the Subtask 1.3 Petroleum Coke IGCC Coproduction Plant has a design capacity of 5,399 TPD of dry coke, it could have annual average coke capacities as low as 3,973 TPD or as high as 4,814 TPD depending upon the amount of replicated equipment (capacity factors between 73.6% and 89.2%).

These availability analyses showed the importance of designing plants and equipment that have high on-stream factors and/or require low maintenance (short or infrequent scheduled outages), and sparing or replicating those portions which have low on-stream factors and/or high maintenance (long or frequent scheduled outages).

Attachment A
Availability Nomenclature

The following table of availability nomenclature and definitions is based on material prepared by a working group of the Gasification Technology Council (GTC).[3] They have been supplemented by terms used in this study.

Availability - Defined as the yearly production of the unit or a portion thereof divided by the design production, expressed as a percentage. When expressed on a time basis, the percent of time the unit(s) is operating at a useable capacity.

Average Daily Production – The yearly production divided by 365.

Capacity Factor – Defined as the yearly production of the unit divided by the design production, expressed as a percentage.

Design Production – Defined as the maximum production that the unit would produce at the design rate over the calendar year when operated in an integrated manner. Calculated by multiplying the average annual daily design rate by 365. Note that the Design Production can change over time as the plant is debottlenecked.

Equivalent Availability – Similar to availability. Average annual daily production rate divided by the design production rate, expressed as a percentage.

Forced Outage Rate – Defined as the time during which the downstream unit or customer did not receive product divided by the time during which they expected product, expressed as a percentage.

On-Stream – Percent of the year the unit was operating and supplying product in a quantity useful to the downstream unit or customer.

Planned Outages – Percent of the year that the unit is not operated due to outages which were scheduled at least one month in advance. Includes yearly planned outages as well as maintenance outages with more than an one month notice.

Product Not Required – Percent of the year that the product from the unit was not required, and therefore, the unit was not operated. The unit was generally available to run and not in a planned or forced outage.

Unplanned Outages – Percent of the year the unit was not operated due to forced outages which had less than one month notice. Includes immediate outages as well as maintenance outages with less than one month notice.

Yearly Production – Defined as the total product actually produced from the unit in a calendar year. For the gasification units, the GTC prefers to have production reported on the basis of total fuel LHV.

[3] James M. Childress, email entitled “Gasification Plant Availability Reporting Guidelines, Oct. 4, 2001.

Appendix K

Design Bases

Appendix K

Design Bases

This appendix contains the detailed Design Bases (Technical Work Plans) that were developed for Subtasks 1.1 through 1.7. Detailed work plans were not developed for Subtasks 1.8 and 1.9.

The following five subsections contain the Design Bases/Goals that were developed for Subtasks 1.1 through 1.7.

- Design Bases for Subtasks 1.1 and 1.2
- Design Bases for Subtasks 1.3 and 1.4
- Design Basis for Subtask 1.5 – Large Single-Train Power Plants
- Design Basis for Subtask 1.6 – A Nominal 1,000 MW Coal IGCC Power Plant
- Design Basis for Subtask 1.7 – A Coal to Hydrogen Power Plant

Addendum 1 to the statement of work (October 18, 2000) provides sufficient information to accomplish Subtasks 1.8 and 1.9 without requiring the development of separate, more detailed work plans. The following paragraphs contain the descriptions of these subtasks from the statement of work that served as the design basis for these two subtasks.

Subtask 1.8 –Warm Gas IGCC Clean-up Technology Review

This subtask will review the status of available hot gas cleanup technologies. It will consider and search for new developing technologies over a moderate (warm) temperature range from 500^{o}F to 750^{o}F. This is the preferred temperature region for Global Energy's gasification technology. It will describe and provide an estimate of the potential savings from implementation of the most promising technology when applied to the Subtask 1.4 design. [Note: The temperature range was subsequently extended down to 300^{o}F at the request of the DOE.]

Subtask 1.9 - Availability Analysis

This subtask will discuss the analysis done as part of the availability and reliability design optimization portion of the VIP program. It will include historic data from the Wabash River plant and tabulated projections for the optimized cases. It also will include a discussion of how availability analysis and design considerations, such as the expected annual coke consumption, affect the sparing philosophy.

Design Bases for Subtasks 1.1 and 1.2

Design Bases for Subtasks 1.1 and 1.2
Table of Contents

1.0 Introduction

The objective of these Design Bases (Technical Plans) is to define the process units and process support units including plant configurations for Subtasks 1.1 and 1.2. This section includes the design basis and criteria for the subsequent engineering study and capital cost estimates. Subtasks 1.1 and 1.2 are the base cases for the later optimized cases, Subtasks 1.3 and 1.4, and are defined as follows:

- Subtask 1.1 - Convert the Wabash River Repowering Project design to a stand-alone Integrated Gasification and Combined Cycle (IGCC) plant at a green-field site. Site is a generic Mid-Western location, using Mid-Western/Eastern coals as feedstocks. All costs are to be adjusted to a year 2000 basis.

- Subtask 1.2 - Convert the Subtask 1.1 facility into a petroleum coke fueled Integrated Gasification Combined Cycle (IGCC) Coproduction Plant coproducing electric power, steam, and hydrogen. Site to be located on Gulf Coast.

2.0 Subtask 1.1 – Wabash River Greenfield Plant

2.1 Plant Description

The Wabash River Greenfield Plant will be based on the Wabash River Repowering Project and will consist of the following process blocks and subsystems:

- Fuel Handling

- Gasification
  - Slurry Preparation
  - Slag Handling
  - Gasifier / High Temperature Heat Recovery (HTHR) / Filtration
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block
  - Gas Turbine (GT) /Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator (STG) / Auxiliary Equiptment

- Balance of Plant
  - Startup Fuel System
  - Instrument and Service Air System
  - Cooling Water System
  - Flare System
  - Firewater System

- Plant Water Intake
- Water Treatment
- Waste Water Outfall
- Distributed Control System (DCS)
- Switch Yard
- Plant Roads
- Buildings
- Chemical Storage
- Fence and Security
- Communication System

A block flow diagram of the Wabash River Greenfield Plant is shown in Figure 1.

2.2 Site Selection

The Wabash River Greenfield Plant will be located at a generic Mid-Western site near the feedstock, in expectation of a higher realistic market potential.

2.3 Feed Stocks

The feedstocks for the coal to power facility will be Mid-Western and/or Eastern bituminous coals with a maximum sulfur content of 6 wt% on a dry basis. Coal delivery to the site is by rail.

2.4 Plant Capacity

The plant will process approximately 2,500 TPD of as-received coal (note that this greenfield plant design is based on the proven, existing, and the largest single gasifier train operating at the Wabash River site) to generate syngas that is combusted in a General Electric 7FA gas turbine to produce 192 MW of electricity.

2.5 Configuration

The plant has two 100% gasifier vessels, one operating and one spare. Each gasifier is Global Energy's two-stage design with 2,500 TPD of coal capacity. The operating pressure of the gasifier is 400 psig.

2.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - One syngas cooler, Steam export to the Gas Turbine Generator (GTG) and HRSG train for superheating. Two 50% particulate removal filters.

- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber

- Acid Gas removal - Amine type with 98% sulfur removal

- Sulfur Removal - Claus unit with tail gas recycle to gasifier

2.7 Air Separation Unit (ASU)

The Air Separation Unit is a non-integrated plant producing approximately 2,100 TPD of oxygen of 95% purity

2.8 Power Block

Gas Turbine - General Electric 7F. Nominal rating is 192 MW with steam injection and syngas moisturization.

Steam Turbine - A new Steam Turbine Generator (STG) will be specified. The STG will be based on a reheat, condensing machine. Inlet steam conditions will be the same as at Wabash River. Turbine power will reflect the steam energy available from one GTG / HRSG train.

2.9 Power Output

To be determined based on the above criteria.

3.0 Subtask 1.2 – Petroleum Coke IGCC Coproduction Plant

3.1 Plant Description

The Petroleum Coke IGCC Coproduction Plant consists of the following process blocks and subsystems:

- Fuel Handling

- Gasification
  - Slurry Preparation
  - Slag Handling
  - Gasifier / HTHR / Filtration
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Hydrogen Production
  - CO Shift
  - Pressure Swing Adsorption (PSA)
  - Hydrogen Compression

- Power Block
  - Gas Turbine (GT) / Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator (STG) / Auxiliary Equipment

- Balance of Plant
  - Startup Fuel System
  - Instrument and Service Air System
  - Cooling Water System
  - Flare System
  - Firewater System
  - Plant Water Intake
  - Water Treatment
  - Waste Water Outfall
  - DCS
  - Switch Yard
  - Plant Roads
  - Buildings
  - Chemical Storage
  - Fence and Security
  - Communication System

A block flow diagram of the Petroleum Coke IGCC Coproduction Plant is shown in Figure 2.

3.2 Site Selection

The Petroleum Coke IGCC Coproducition plant will be located at a generic Gulf Coast site adjacent to a pertroleum refinery for synergy and integration with the refininery.

3.3 Feed Stock

The sulfur content of the delayed coke will be less than 7 wt% on a dry basis. Coke delivery is by conveyor or rail car from the adjacent refinery.

3.4 Plant Capacity

The plant will process approximately 5,500 TPD of as-received petroleum coke. (Note: Approximately 80,000 BPSD of coker capacity are required to support this coke rate.) The 5,500 TPD coke rate was selected as the design capacity because it will

1. Support the coproduction of hydrogen and steam, as needed, for a typical refinery
2. Power two General Electric 7FA gas turbines to produce electricity, and
3. Use two of the largest proven (existing) single gasifier trains running in parallel.

3.5 Configuration

The plant has three 50% gasifier trains, two operating and one spare, with one gasifier per train. Each gasifier is Global Energy's two-stage design operating at 400 psig pressure with 2,500 TPD of coke capacity. This configuration was selected because it is based on

1. The existing and proven capacity and performance of Global Energy's gasifier,
2. Gasifier capacity to fully load two General Electric 7FA GTGs, and
3. To produce approximately 79 MMscfd of hydrogen.

3.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - Three syngas coolers, one for each gasification train. Steam export to GTG and HRSG train for superheating. Two Particulate Removal Filter units per train.
- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber
- Acid Gas removal - Amine type with 99.5% sulfur removal
- Sulfur Removal - Claus unit with tail gas recycle to the gasifier

3.7 Air Separation Unit (ASU)

Two non-integrated plants will supply oxygen at 95% purity. Steam will be used for GTG power enhancement and NOx control. No nitrogen, oxygen or argon export.

3.8 Power Block

Gas Turbine - Two General Electric 7FA models. Flat rating is 192 MW, each with natural gas back-up and start-up fuel.

Steam Turbine - The STG will be based on a reheat, condensing machine. Inlet steam conditions may not necessarily be the same as at the Wabash River Plant. Turbine power will reflect the steam energy available from the two GTG / HRSG trains.

3.9 Power Output

To be determined based on the above criteria.

3.10 Hydrogen Production

Capacity - 79 MMscfd hydrogen
H2 Purity - 99%
H2 Delivery Pressure – 1,000 psig
Process units - CO shift and pressure swing adsorption (PSA) units.

Compared to the conventional hydrogen plant (with solution absorption CO_2 removal unit), a PSA unit has the following advantages:

- Capital cost may be lower when high pressure and high purity hydrogen is required. The PSA unit has lower cost when the conventional scheme is designed for greater than 98% purity. When the hydrogen is used at high pressure, compression savings for the PSA unit are significant.
- Lower operating cost. No steam and absorption solution consumption.
- Higher reliability. Except for the automatically controlled valves, the PSA has no moving parts.
- Less maintenance. The PSA unit is designed to operate outdoors, unattended, and needs no regular maintenance except for the replacement of valve springs every few years.
- More flexibility. Hydrogen purity can usually be handled by adjustment of the PSA cycle. Shutdown for maintenance can be postponed until a convenient time.
- High purity product. Increased hydrogen purity by removing CO_2, as well as CO and other impurities.

4.0 Site Conditions

	Subtask 1.1	**Subtask 1.2**
Location	Typical Mid-Western State	U.S. Gulf Coast near a Petroleum Refinery
Elevation	500 ft above sea level	25 ft above sea level
Air Temperature		
Maximum, °F	93	95
Annual Average, °F	59	70
Minimum, °F	-20	29
Summer Wet Bulb,°F	70	80
Relative Humidity, %	60	60
Barometric Press, psia	14.43	14.7
Seismic Zone	2B	0
Design Wind Speed, MPH	70	120

5.0 Feeds

Type	Coal		Petroleum Coke	
Feedstock	Illinois #6		Green Delayed Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	14,132
LHV, Btu/lb	12,275	10,495	14,548	13,846
Analysis, wt %				
Carbon	70.02	59.87	88.76	82.55
Hydrogen	4.99	4.27	3.20	2.98
Nitrogen	1.30	1.11	0.90	0.84
Sulfur	2.58	2.21	7.00	6.51
Oxygen	8.27	7.07	0	0
Chlorine	0.13	0.11	50 ppm	47 ppm
V & Ni	Nil	Nil	1900 ppm	1767 ppm
Ash	12.70	10.86	0.14	0.13
Moisture	NA	14.50	NA	6.99
Total	100	100	100	100

6.0 Syngas (Leaving the Sulfur Removal Unit)

	Subtask 1.1	Subtask 1.2
Heating Value, Btu/scf	275	290
Composition, mole % (dry)		
Carbon Monoxide	46.8	59.4
Hydrogen	33.3	23.8
Carbon Dioxide	14.8	11.2
Nitrogen	1.6	1.1
Argon	1.2	1.3
Methane	2.3	3.2
Total	100	100

7.0 Electric Power

	Subtask 1.1	Subtask 1.2
Export Power, MW	269.3	396
Voltage, kV	230	230

Transmission and substation costs will be included in the plant estimate.

8.0 Export Steam Production

	Subtask 1.1	Subtask 1.2
Medium Pressure Steam		
Flow Rate, lb/hr	0	980,000
Pressure at Delivery, psig	NA	700
Temperature at Delivery, °F	NA	750

9.0 Hydrogen Production

	Subtask 1.1	Subtask 1.2
Flow Rate, MMscfd	0	79
Purity, %	NA	99
Pressure, psig	NA	1000
Temperature, °F	NA	120

10.0 Water Makeup

	Subtask 1.1	Subtask 1.2
Source	Wabash River	Sabine River
Supply Pressure, psig	50	50
Supply Temperature, °F	70	70

11.0 Natural Gas

	Subtask 1.1	Subtask 1.2
HHV, Btu/scf	1,000	1000
LHV, Btu/scf	900	900
Value, HHV basis, $/MM Btu	2.60	2.60

12.0 By-Products

	Subtask 1.1	Subtask 1.2
Slag, tons/day	356	190
Sulfur, tons/day	57	367

13.0 Wastes

	Subtask 1.1	Subtask 1.2
Waste Water, gpm	120	TBD
Gas Emissions		
Particulates	Nil	Nil
SOx, as SO_2	240 lb/hr (<0.1 lb/MMBtu)	> 99.5 % Removal
NOx, as NO_2	152 lb/hr (<25 ppmvd)	< 25 ppmvd
CO	120 lb/hr	< 15 ppmvd

Figure A1

WABASH RIVER GREENFIELD PLANT
BLOCK FLOW DIAGRAM
(Subtask 1.1)

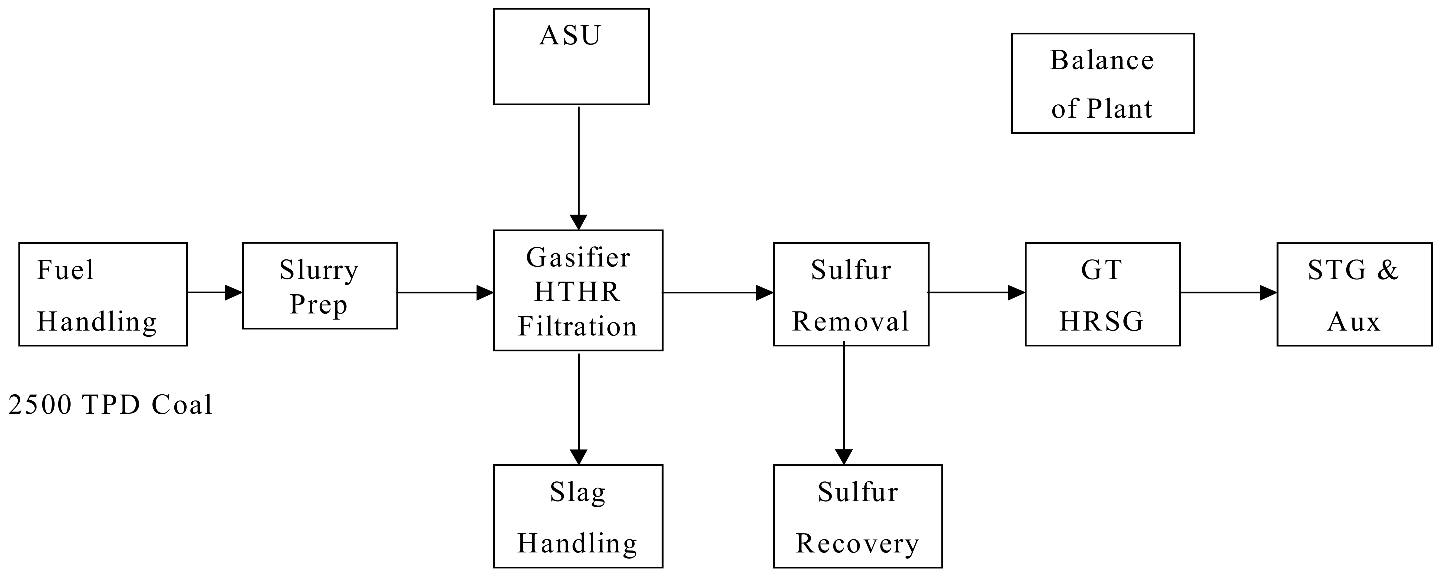
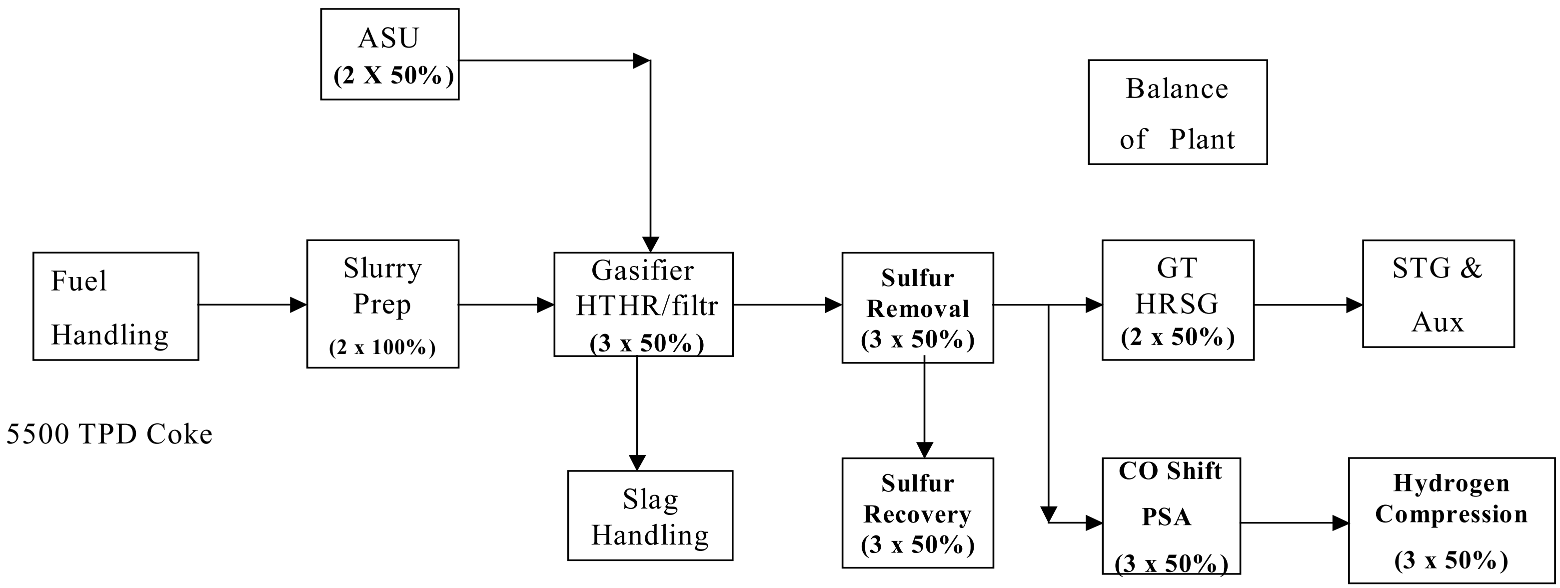


Figure A2

PETROLEUM COKE IGCC COPRODUCTION PLANT BLOCK FLOW DIAGRAM

(Subtask 1.2)



Design Bases for Subtasks 1.3 and 1.4

Design Bases for Subtasks 1.3 and 1.4
Table of Contents

Section

Figures

1.0 Introduction

The objective of these Design Bases (Technical Plans) is to define the process units and process support units including plant configurations for Subtasks 1.3 and 1.4. This section includes the design bases and data for the subsequent engineering study and capital cost estimates. Subtasks 1.3 and 1.4 are the optimized cases from the Subtask 1.2 and 1.1 base cases, respectively, and they are defined as follows:

- Subtask 1.3 - Optimize the Subtask 1.2 facility into a petroleum coke fueled Integrated Gasification Combined Cycle (IGCC) Coproduction Plant coproducing electric power, steam, and hydrogen by using both Global Energy's petroleum coke experience and Bechtel's engineering tools, standard engineering practices, value improvement practices, and procurement acquisition techniques. Site to be located on Gulf Coast.

- Subtask 1.4 - Optimize the Subtask 1.1 design to a stand-alone Integrated Gasification and Combined Cycle (IGCC) plant at a green-field site by using the most advanced gas turbine available in the 60Hz market available in the year 2010. Site is a generic Mid-Western location, using Mid-Western/Eastern coals as feedstocks.

2.0 Subtask 1.3, Optimized Petroleum Coke IGCC Coproduction Plant

2.1 The block flow diagrams (BFD) for Subtask 1.2 and 1.3 have essentially identical conceptual representations, and the BFD from Subtask 1.2 is the starting point for plant optimization. However, the number of trains for process blocks will be optimized for Subtask 1.3. We will also optimize equipment redundancy within each process areas to reduce capital cost while maintaining the availability targets. The optimized petroleum coke IGCC coproduction plant consists of the following process blocks and subsystems:

- Fuel Handling

- Gasification

  - Slurry Preparation
  - Slag Handling
  - Gasifier / High Temperature Heat Recovery (HTHR) / Filtration
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Hydrogen Production

  - CO Shift
  - Pressure Swing Adsorption (PSA)
  - Hydrogen Compression

- Power Block

  - Gas Turbine (GT) / Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator (STG) / Auxiliary Equipment

- Balance of Plant

  - Startup Fuel System
  - Instrument and Service Air System
  - Cooling Water System
  - Flare System
  - Firewater System
  - Plant Water Intake
  - Water Treatment
  - Waste-Water Outfall
  - Distributed Control System (DCS)
  - Switch Yard
  - Plant Roads
  - Buildings
  - Chemical Storage
  - Fence and Security
  - Communication System

A block flow diagram of the above subsystems is shown in Figure 1. This BFD shows fewer process trains reflecting an anticipated impact of optimization.

2.2 Site Selection

The petroleum coke IGCC coproduction plant will be at adjacent to a Gulf Coast refinery for synergy and integration with the refinery.

2.3 Feed Stocks

The sulfur content of the delayed coke is to be 7 wt% or less, dry basis. Coke delivery is by conveyor or rail car from the adjacent refinery.

2.4 Plant Capacity

The plant will process approximately 5,400 TPD (dry) of petroleum coke. (Note: requires approximately 80,000 BPSD coker capacity to support this capacity). This size was selected for the coproduction of hydrogen and steam for a typical refinery, and electricity from two GE 7FA+e gas turbines. As part of the optimization for Subtask 1.2, the GE 7FA gas turbine will be upgraded to 7FA+e for Subtask 1.3. This reflects an expected improvement from current commercial available units as a result of an increased gas turbine firing temperature.

2.5 Configurations

The optimization exercise will target achieving high product availability with two 50% gasifier trains (compared to three 50% gasifier trains in Subtask 1.2). The gasifier is a Global Energy's two-stage design with about 2,600 TPD coke capacity each. This is the starting point based on the Global Energy's existing and proven gasifier capacity and performance, to fully load two GE 7FA+e gas turbine generators (GTGs) and produce approximately 80 MMscfd of hydrogen. The gasifier operating pressure will be about 400 psig.

2.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - two syngas coolers, one for each gasification train. Steam export to the GTG and HRSG trains for superheating. Two particulate removal filter units per train.

- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber

- Acid Gas removal - Amine type with 99.5% sulfur removal

- Sulfur Recovery - Claus unit with tail gas recycle to gasifier

2.7 Air Separation Unit

Two non-integrated plants will supply oxygen at 95% purity. Steam will be used for GTG power enhancement and NOx control. No nitrogen, oxygen or argon export.

2.8 Power Block

Gas Turbine - Two General Electric 7FA+s turbines. Flat rating is to be determined later by GE. Steam diluent will be used for NOx control and added power.

Steam Turbine - The steam turbine generator (STG) will be based on a reheat, condensing machine. The steam cycle from Subtask 1.2 (1450 psig/1000°F/1000°F) will be the starting point for optimization of the steam cycle. Turbine power will reflect the steam energy available from two GTG/HRSG trains.

2.9 Power Output

To be determined based on the above criteria.

2.10 Hydrogen Production

Capacity - 80 MMscfd of hydrogen
Hydrogen Purity - 99%
H2 Delivery Pressure – 1,000 psig
Process Units - CO shift and pressure swing adsorption (PSA) units.

3.0 Subtask 1.4, Future Optimized Coal to Power IGCC Plant

3.1 The future Optimized Coal to Power IGCC Plant consists of the following process blocks and subsystems:

- Fuel Handling
- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier / HTHR / Filtration
    - Sulfur Removal
    - Sulfur Recovery
- Air Separation Unit
- Power Block
    - GTG / HRSG
    - STG / Auxiliary Equipment
- Balance of Plant
    - Startup Fuel System
    - Instrument and Service Air System
    - Cooling Water System
    - Flare System
    - Firewater System
    - Plant Water Intake
    - Water Treatment
    - Waste-Water Outfall
    - DCS
    - Switch Yard
    - Plant Roads
    - Buildings
    - Chemical Storage
    - Fence and Security
    - Communication System

A block flow diagrams of the above subsystems is show in Figure 2.

3.2 Site Selection

The optimized coal to power IGCC plant will be at a generic Mid-Western location near the feedstock in expectation of a higher realistic market potential.

3.3 Feed Stocks

The facility will use Mid-Western and/or Eastern bituminous coals with a sulfur content of 6 wt% or less, dry coal basis. Coal delivery to the site is by rail.

3.4 Plant Capacity

The plant will process approximately 3,000 TPD of dry coal to generate syngas that is combusted in an "H-class" gas turbine. The GE 7H gas turbine is the most advanced machine that is expected to be available commercially in the year 2010. It was estimated that approximately 3,000 TPD of dry coal will be required to produce sufficient syngas to fully load this gas turbine.

3.5 Configurations

The starting point for optimization is a plant with two-50% gasifier vessels with no spare. The gasifier is a Global Energy's two-stage design with 1,850 TPD coal capacity each. The operating pressure of the gasifier is about 400 psig. This configuration will be optimized to maximize NPV.

3.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - one syngas cooler per gasifier. Steam export to the GTG and HRSG train for superheating. Two 50% particulate removal filters.
- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber
- Acid Gas removal - Amine type with 99% sulfur removal
- Sulfur Removal - Claus unit with tail gas recycle to gasifier

3.7 Air separation Unit

A partially-integrated plant with 95% oxygen purity.

3.8 Power Block

Gas Turbine – "H-class" design - Nominal rating is to be determined by General Electric later. Nitrogen diluent will be used for NOx control.

Steam Turbine - A new STG will be specified. The STG will be based on a reheat, condensing machine. Turbine power will reflect the steam energy available from one GTG / HRSG train.

3.9 Power Output

To be determined based on the above criteria.

4.0 Value Improvement Practices (VIP)

Value Improvement Practices will be applied to Subtasks 1.3 and 1.4 to reduce project investment costs by lowering total-installed costs (TIC) and reducing life-cycle costs (increasing Net Present Value, NPV).

The following VIPs are industrial standard practices, and normally used to form the basis for developing a project-specific VIP program:

- Technology Selection - Search for new or improved technologies.
- Process Simplification - Reduce capital cost by combining or eliminating process steps.
- Classes of Plant Quality - Use to determine design allowance, redundancy, sparing philosophy, and room for expansion.
- Waste Minimization - Reduce or eliminate waste products, or convert the waste into a salable commodity.
- Process Reliability Modeling - Use of computer simulation of processes to explore the relationship between the maximum production rates and design and operational factors.
- Appropriate Standards and Specifications - Consider the needs of the project, and select standards and specifications that optimally meet these needs.
- Predictive Maintenance - Incorporate advance sensor and instrumentation into project design.
- Design to Capacity - Evaluate the maximum capacity of each piece of equipment, and precisely align equipment, units, systems, and bulks within a range of capacity performance.
- Energy Optimization - Identify the most economical level of heat recovery and power generation, and establish the energy target that corresponds to the optimized cost.
- Traditional Value Engineering - Eliminate or modify items that do not add value to project needs.

- Constructability Reviews - Reduce costs or save time during the construction phase.

5.0 Site Conditions

	Subtask 1.3	**Subtask 1.4**
Location	Gulf Coast Refinery	Typical Mid-western State
Elevation	25 ft above sea level	500 ft above sea level
Air Temperature		
Maximum, °F	95	93
Annual Average, °F	70	59
Minimum, °F	29	-20
Summer Wet Bulb,°F	80	70
Relative Humidity, %	60	60
Barometric Press, psia	14.7	14.7
Seismic Zone	0	2B
Design Wind Speed, MPH	120	70

6.0 Feeds

Type	**Petroleum Coke**	**Coal**
Feedstock	Green Delayed Coke	Illinois # 6

	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	14,848	14,132	12,749	10,900
LHV, Btu/lb	14,548	13,846	12,275	10,495
Analysis, Wt %				
Carbon	87.86	83.62	69.9	59.76
Hydrogen	3.17	3.02	5.0	4.28
Nitrogen	0.89	0.85	1.3	1.11
Sulfur	6.93	6.60	2.58	2.21
Oxygen	1.0	0.95	8.27	4.96
Chlorine	0.01 ppm	0.01 ppm	0.13	0.11
V & Ni	1900 ppm	1812 ppm	Nil	Nil
Ash	0.14	0.13	12.7	10.86
Moisture	NA	NA	NA	14.5
Total	100	100	100	100

7.0 Syngas (from Sulfur Removal Unit)

	Subtask 1.3	Subtask 1.4
HHV, Btu/scf (dry)	290	275
Compositions, mole % (dry)		
Carbon monoxide	57.0	47.4
Hydrogen	29.8	32.0
Carbon dioxide	9.3	15.7
Nitrogen	1.8	1.7
Argon	1.2	1.2
Methane	0.9	2.0
Total	100	100

8.0 Electric Power

	Subtask 1.3	Subtask 1.4
Export Power, MW	TBD	TBD
Voltage, kV	230	230

Transmission and substation costs to be included in the IGCC plant estimate.

9.0 Steam Production - Export

	Subtask 1.3	Subtask 1.4
Medium Pressure Steam		
Flow Rate, Lb/hr	980,000	NA
Pressure at Delivery, psig	700	NA
Temperature at Delivery, °F	750	NA

10.0 Hydrogen Production

	Subtask 1.3	Subtask 1.4
Flow Rate, MMscfd	80	0
Purity, %	99	NA
Pressure, psig	1,000	NA
Temperature, °F	120	NA

11.0 Water Makeup

	Subtask 1.3	Subtask 1.4
Source	Sabine River	Wabash River
Supply Pressure, psig	TBD	50
Supply Temperature, °F	TBD	70

12.0 Natural Gas

	Subtask 1.3	Subtask 1.4
HHV, Btu/scf	1,000	1,000
LHV, Btu/scf	900	900
Value, HHV basis, $/MM Btu	TBD	TBD

13.0 By-Products

	Subtask 1.3	Subtask 1.4
Slag, Tons/day	100	400
Sulfur, Tons/day	300	90

14.0 Wastes

	Subtask 1.3	Subtask 1.4
Waste Water, gpm	180	160
Gas Emissions *		
Particulates	Nil	Nil
SO x	> 99.5 % Removal	> 99 % Removal
NO x	<15 ppmvd @15% O2	<15 ppmvd @15% O2
CO	< 15 ppmvd	< 15 ppmvd

* Values to be confirmed with gas turbine manufacturer after completion of value improvement practices activities.

15.0 Cost Estimate

The cost estimate performed fo Subtask 1.2, the stand-alone petroleum coke IGCC coproduction plant, will be revised to reflect the cost savings and changes as a result of the above optimization steps to arrive with a new and optimized Total Installed Cost (TIC) estimate for Subtask 1.3.

A Net Present Value (NPV) calculation will be prepared to reflect this new plant configuration and its reduced TIC.

A TIC for Subtask 1.4, the stand-alone optimized coal to power IGCC plant,, will be prepared as the result of the optimization steps above.

Figure 1
OPTIMIZED PETROLEUM COKE IGCC COPRODUCTION PLANT SIMPLIFIED BLOCK FLOW DIAGRAM

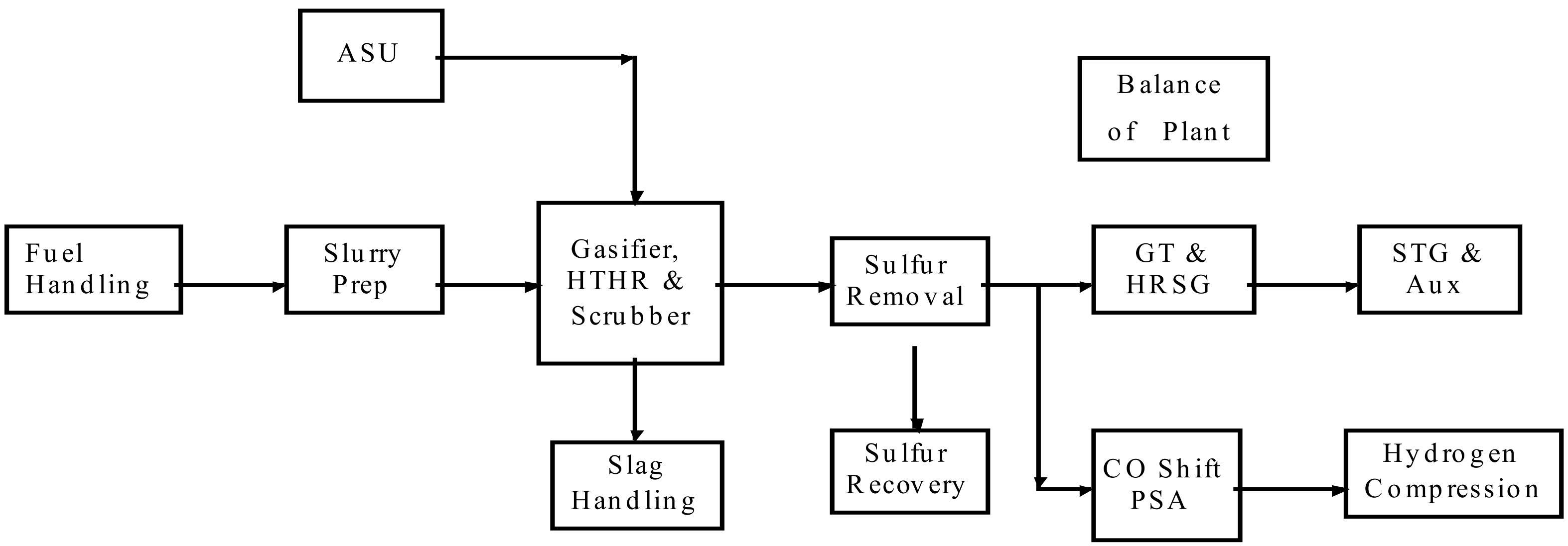
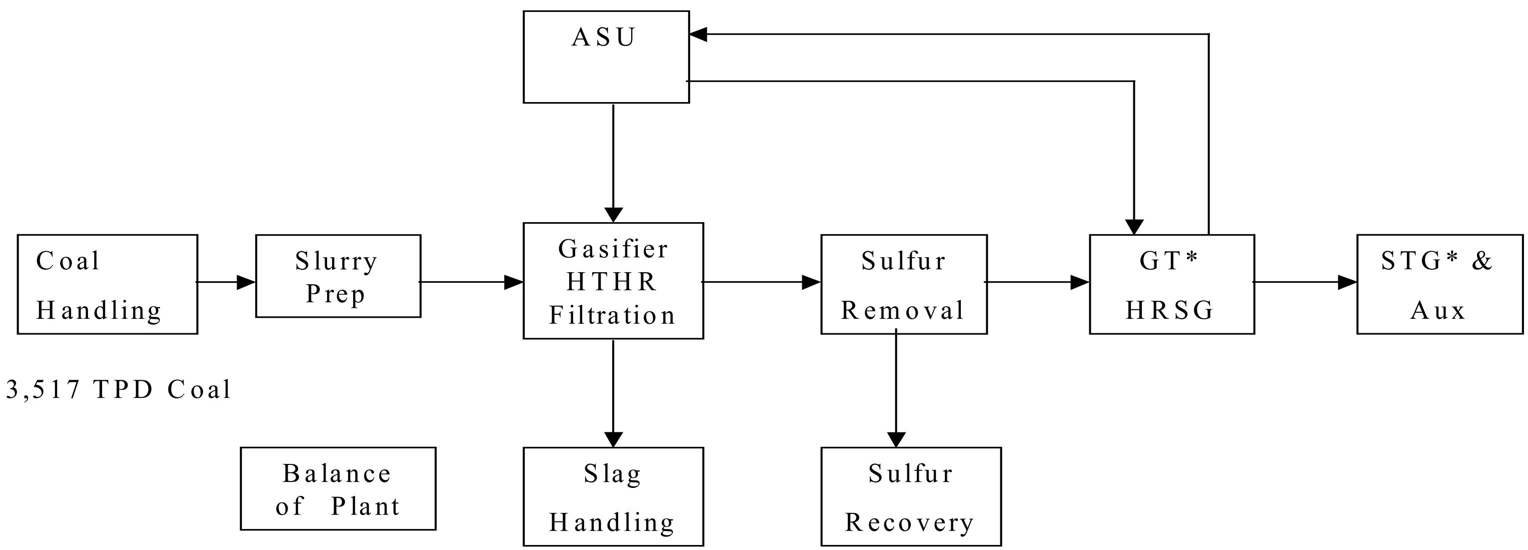


Figure 2
FUTURE OPTIMIZED COAL TO POWER IGCC PLANT



Design Basis for Subtask 1.5

Large Single-Train Power Plants

Design Basis for Subtask 1.5
Table of Contents

1.0 Introduction

The objective of Subtask 1.5 is to develop designs and cost information for two large single-train power plants, one fueled by coal and one fueled by petroleum coke, and to highlight the differences between these two plants.

This Design Basis (Technical Plan) defines the process units and process support units including plant configurations to accomplish the objectives of Subtask 1.5. The coal fueled power plant will be handled in Subtask 1.5A, and the petroleum coke fueled power plant will be handled in Subtask 1.5B. This plan provides the design basis and data for the subsequent engineering study and capital cost estimates. Subtasks 1.5A and 1.5B are the large single-train cases that will be developed from the Subtask 1.3 case and are defined as follows:

- Subtask 1.5A – Convert the Subtask 1.3 design to a stand-alone, coal fueled single-train Integrated Gasification and Combined Cycle (IGCC) power plant at a green-field site using the most advanced 60 Hz gas turbine currently available. The plant is to be located at a generic U. S. Gulf Coast site, using Mid-Western/Eastern coals as feedstocks. Illinois No. 6 coal will be the design feedstock.

- Subtask 1.5B – Convert the Subtask 1.3 design to a stand-alone, single-train petroleum coke fueled Integrated Gasification and Combined Cycle (IGCC) power plant at a green-field site using the most advanced 60 Hz gas turbine currently available. The plant is to be located at a generic U. S Gulf Coast site.

2.0 Subtask 1.5A, Single-Train Coal IGCC Power Plant

2.1 Plant Description

The Single-Train Coal IGCC Power Plant consists of the following process blocks and subsystems:

- Fuel Handling

- Gasification

  - Slurry Preparation
  - Slag Handling
  - Gasifier / High Temperature Heat Recovery (HTHR) / Wet Scrubbing
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block
    - Gas Turbine (GT) / Heat Recovery Steam Generator (HRSG)
    - Steam Turbine Generator (STG) / Auxiliary Equipment

- Balance of Plant
    - Startup/Backup Fuel System
    - Instrument and Service Air System
    - Cooling Water System
    - Flare System
    - Firewater System
    - Plant Water Intake
    - Water Treatment
    - Waste Water Outfall
    - DCS
    - Switch Yard
    - Plant Roads
    - Buildings
    - Chemical Storage
    - Fence and Security
    - Communication System

The block flow diagram of the Single-Train Coal IGCC Power Plant is shown in Figure 1.

2.2 Feedstocks

The feedstocks for the coal to power facility will be Mid-Western and/or Eastern bituminous coals with a maximum sulfur content of 3 wt% on a dry basis. Illinois No 6. Coal will be the design feedstock. Coal delivery to the site is by rail.

2.3 Site Selection

The Single-Train Coal IGCC Plant will be located at a level and cleared generic U. S. Gulf Coast site. This site was selected to provide a direct cost comparison with the Subtask 1.5B case even though the design feedstock will be Illinois No. 6 coal.

2.4 Plant Capacity

The plant will process approximately 2,400 TPD coal to generate syngas that is combusted in a General Electric 7FA+e gas turbine. The GE 7FA+e gas turbine is the most advanced machine that is currently commercially available. This coal rate was selected as the design capacity because it will fully load a GE 7FA+e gas turbine with syngas.

2.5 Configurations

The design starting point is a single gasification vessel with no spare. The gasifier is Global Energy's two-stage design with about 2,400 TPD coal capacity and slurry quench. The gasifier operating pressure will be about 400 psig. The plant configuration will allow supplemental firing with natural gas to produce power when syngas is unavailable.

2.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - One syngas cooler. Steam export to the GTG and HRSG train for superheating. Particulate removal will be by a wet scrubbing system.

- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber

- Acid Gas removal - Amine type with 99% sulfur removal

- Sulfur Removal - Claus unit with tail gas recycle to the gasifier

2.7 Air Separation Unit (ASU)

One non-integrated air separation unit will produce oxygen at 95% purity. There will be no nitrogen, oxygen or argon export.

2.8 Power Block

- Gas Turbine - General Electric 7FA+e. Nominal rating is 210 MWe. Steam will be used for GTG power enhancement and NOx control.

- Steam Turbine - A reheat, condensing STG will be specified. Turbine power will reflect the steam energy available from the GTG / HRSG train.

2.9 Power Output

To be determined based on the above criteria.

3.0 Subtask 1.5B, Single-Train Petroleum Coke IGCC Power Plant

3.1 Plant Description

The Single-Train Petroleum Coke IGCC Power Plant will consist of the following process blocks and subsystems:

- Fuel Handling

- Gasification

  - Slurry Preparation
  - Slag Handling
  - Gasifier / High Temperature Heat Recovery (HTHR) / Wet Scrubbing
  - Sulfur Removal
  - Sulfur Recovery

- Air Separation Unit (ASU)

- Power Block

  - Gas Turbine (GT) / Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator (STG) / Auxiliary Equipment

- Balance of Plant

  - Startup/Backup Fuel System
  - Instrument and Service Air System
  - Cooling Water System
  - Flare System
  - Firewater System
  - Plant Water Intake
  - Water Treatment
  - Waste-Water Outfall
  - Distributed Control System (DCS)
  - Switch Yard
  - Plant Roads
  - Buildings
  - Chemical Storage
  - Fence and Security
  - Communication System

The block flow diagram of the Single-Train Petroleum Coke IGCC Power Plant is essentially the same as that for the Single-Train Coal IGCC Power Plant, and it is shown in Figure 1.

3.2 Feedstock

The sulfur content of the delayed petroleum coke will be less than 7 wt% on a dry basis. Coke delivery is by conveyor or rail car from a nearby petroleum refinery.

3.3 Site Selection

The Single-Train Petroleum Coke IGCC Power Plant will be located at a level and cleared generic U. S. Gulf Coast site. This location was selected because it is close to numerous petroleum refineries.

3.4 Plant Capacity

The plant will process approximately 2,000 TPD of petroleum coke. (Note: Approximately 20,000 BPSD of coker capacity are required to support this coke rate.). This coke rate was selected as the design capacity because it will fully load a GE 7FA+e gas turbine with sungas.

3.5 Configuration

The design starting point is a single gasification vessel with no spare. The gasifier is Global Energy's two-stage design with about 2,000 TPD petroleum coke capacity. The gasifier operating pressure will be about 400 psig. The plant configuration will allow supplemental firing with natural gas to produce power when syngas is unavailable.

3.6 Gasification Unit

- Syngas Cooler and Syngas Particle Removal - One syngas cooler. Steam export to the GTG and HRSG train for superheating. Particulate removal will be by a wet scrubbing system

- Syngas Treatment Units - COS hydrolysis unit and chlorine scrubber

- Acid Gas removal - Amine type with 99% sulfur removal

- Sulfur Recovery - Claus unit with tail gas recycle to the gasifier

3.7 Air Separation Unit (ASU)

One non-integrated air separation unit will produce oxygen at 95% purity. There will be no nitrogen, oxygen orargon export.

3.8 Power Block

- Gas Turbine - General Electric 7FA+e. Nominal rating is 210 MWe. Steam will be used for GTG power enhancement and NOx control.

- Steam Turbine - A reheat, condensing STG will be specified. Turbine power will reflect the steam energy available from the GTG / HRSG train.

3.9 Power Output

To be determined based on the above criteria.

4.0 Value Improving Practices

The results of the Value Improving Practices (VIPs), which were be applied to Subtasks 1.3 and 1.4 to reduce total-installed costs (TIC) and to reduce the life-cycle costs (increasing the Net Present Value, NPV), will be applied to the Subtask 1.5A and 1.5B plants, where applicable.

The following Value Improvement Practices were used to form the basis for developing the project-specific VIP program used in Subtask 1.3:

- Technology Selection - Search for new or improved technologies; e. g., wet char removal.
- Process Simplification - Reduce capital cost by combining or eliminating process steps.
- Classes of Plant Quality - Use to determine design allowance, redundancy, sparing philosophy, availability emissions reduction, and room for expansion.
- Process Reliability Modeling - Use of computer simulation models to explore the relationship between the maximum production rates and design and operational factors.
- Appropriate Standards and Specifications - Consider the needs of the project, and select standards and specifications that optimally meet these needs.
- Design to Capacity - Evaluate the maximum capacity of each piece of equipment, and precisely align equipment, units, systems, and bulks within a range of capacity performance.
- Traditional Value Engineering - Eliminate or modify items that do not add value to the project.
- Constructability Reviews - Reduce costs and/or save time during project construction

5.0 Site Conditions

Both the Subtask 1.5A and 1.5B IGCC power plants will be located at a generic U. S. Gulf Coast site having the following properties.

Location	Generic U. S. Gulf Coast
Elevation	25 ft above sea level
Air Temperature	
Maximum, °F	95
Annual Average, °F	70
Minimum, °F	29
Summer Wet Bulb,°F	80
Relative Humidity, %	60
Barometric Press, psia	14.7
Seismic Zone	0
Design Wind Speed, MPH	120

6.0 Feedstocks

	Subtask 1.5A	**Subtask 1.5B**
Type	**Coal**	**Petroleum Coke**
Feedstock	Illinois # 6	Green Delayed Coke
	From Subtask 1.4	From Subtask 1.3

	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	14,132
LHV, Btu/lb	12,275	10,495	14,548	13,846
Analysis, wt %				
Carbon	70.02	59.87	87.86	83.62
Hydrogen	4.99	4.27	3.17	3.02
Nitrogen	1.30	1.11	0.89	.85
Sulfur	2.58	2.21	6.93	6.60
Oxygen	8.27	7.07	1.00	0.95
Chlorine	0.13	0.11	0.01	0.01
V & Ni	Nil	Nil	1900 ppm	1812 ppm
Ash	12.70	10.86	0.14	0.13
Moisture	NA	14.50	NA	4.83
Total	100	100	100	100

7.0 Syngas (Leaving the Sulfur Removal Unit)

	Subtask 1.5A	**Subtask 1.5B**
HHV, Btu/scf (dry)	275	290
Composition, mole % (dry)		
Carbon Monoxide	46.8	59.4
Hydrogen	33.3	23.8
Carbon Dioxide	14.8	11.2
Nitrogen	1.6	1.1
Argon	1.2	1.3
Methane	2.3	3.2
Total	100	100

8.0 Electric Power

	Subtask 1.5A	**Subtask 1.5B**
Export Power, MW	TBD	TBD
Voltage, kV	230	230

Transmission and substation costs will be included in the plant estimate.

9.0 Water Makeup

Since both the Subtask 1.5A and 1.5B IGCC power plants will be located at the same generic U. S. Gulf Coast site, the makeup water properties will be the same.

Source	Sabine River
Supply Pressure, psig	50
Supply Temperature, °F	70

10.0 Natural Gas

The same natural gas will be used at both the Subtask 1.5A and 1.5B plants.

HHV, Btu/scf	1,000
LHV, Btu/scf	900
Value, HHV basis, $/MMBtu	2.60

11.0 Estimated By-Products Production Rates

The following by-product production rates are estimated based on the estimated coal and petroleum coke feed rates. There will be no by-product hydrogen or steam production for export.

	Subtask 1.5A	Subtask 1.5B
Slag, tons/day	360	70
Sulfur, tons/day	60	140

12.0 Wastes

	Subtask 1.5A	Subtask 1.5B
Waste Water, gpm	TBD	TBD
Gas Turbine Emissions		
Particulates	Nil	Nil
S	> 99% Removal	> 99% Removal
NOx	<10 ppmvd @15% O_2	<10 ppmvd @15% O_2
CO	< 10 ppmvd	< 10 ppmvd
Total Emissions		
Particulates	Nil	Nil
S	> 98% Removal	> 99% Removal
NOx	< 15 ppmvd	< 15 ppmvd
CO	< 15 ppmvd	< 15 ppmvd

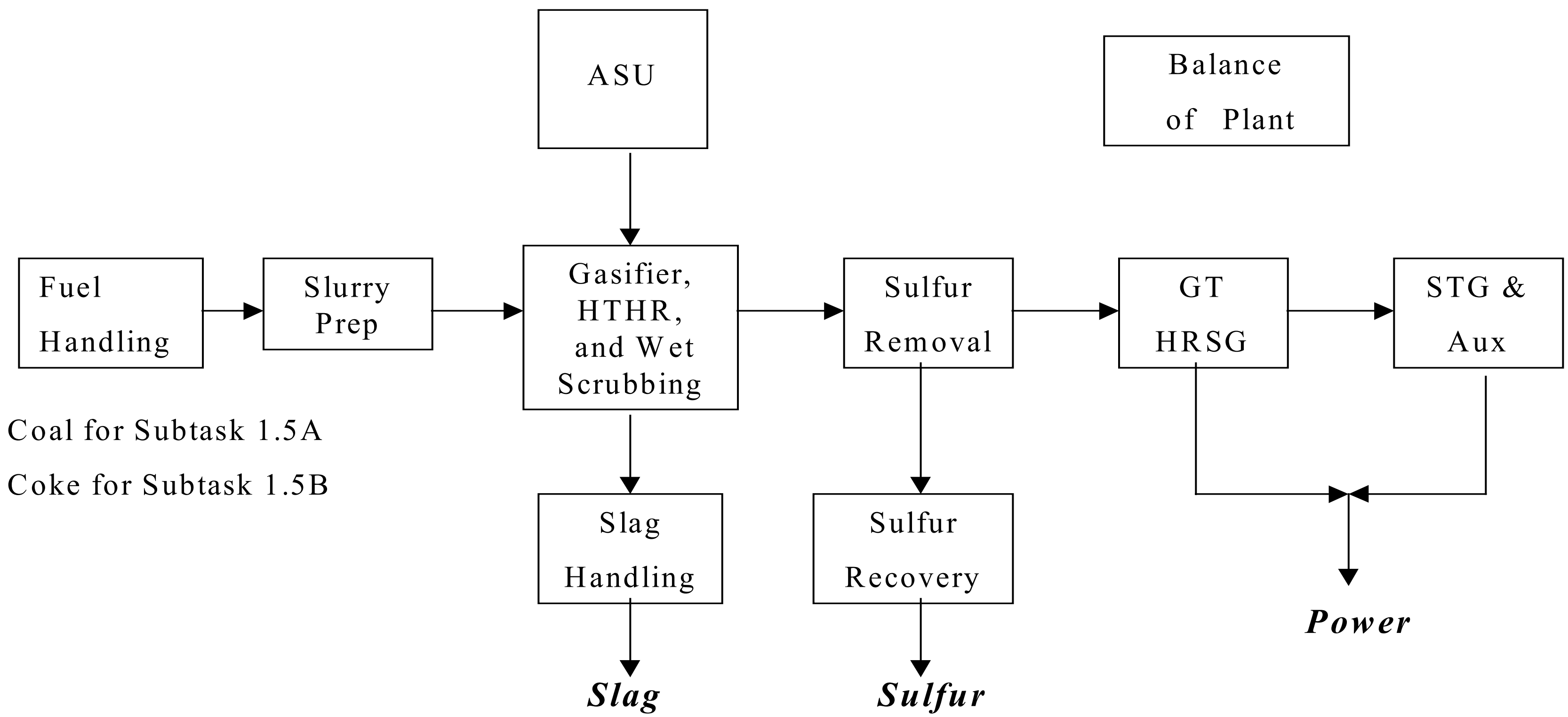
13.0 Cost Estimate

A detailed process simulation model will be developed for each of the Subtask 1.5 cases. The model results will be used to obtain capacities and equipment sizes for the major process blocks. The cost estimates that were developed in Subtask 1.3 for the Optimized Petroleum Coke IGCC Coproduction Plant will be used as the basis for developing the process block cost estimates. The Subtask 1.3 process block cost estimates will be adjusted, as appropriate, to reflect the design and capacity changes for the Subtask 1.5A and 1.5B plants. Thus, for each of the Subtask 1.5A and 1.5B single-train power plants, the Total Installed Cost (TIC) estimate will be developed by combining the cost of the individual process blocks.

Figure 1

SINGLE-TRAIN COAL OR COKE IGCC POWER PLANTS - BLOCK FLOW DIAGRAM

(Subtasks 1.5A and 1.5B)



Design Basis for Subtask 1.6

A Nominal 1,000 MW Coal IGCC Power Plant

Design Basis for Subtask 1.6
Table of Contents

Section

Figure

1.0 Introduction

There has been increasing activities and interest in the United States for very large coal-fueled IGCC plants for power generation. This study will evaluate the merits of a large scale state-of-the-art, optimized IGCC power plant in the mid-west, based on currently available technology. The design basis will be a nominal 1,000 MW IGCC power plant using medium sulfur (~3%) Illinois coal and the currently available General Electric 7FA+e gas turbines. The results of this study will be used to assess whether coal can penetrate the present day domestic power market with the current high cost of natural gas.

The objective of Subtask 1.6 is to develop a process design and cost information for a nominal 1,000 MW coal fueled IGCC power plant located at a generic Illinois site.

This Design Basis (Technical Plan) defines the process units and process support units including the plant configuration required to accomplish the objectives of Subtask 1.6. This plan provides the design basis and basic data for the subsequent engineering study and capital cost estimates. The nominal 1,000 MW coal IGCC power plant will be developed from the Subtask 1.5A case. The Subtask 1.5A case is a large, single-train coal IGCC power plant located at the U. S. Gulf Coast that was sized to fully load one GE 7FA+e gas turbine. The Subtask 1.5A coal plant design was developed from the optimized Subtask 1.3 Petroleum Coke IGCC Coproduction Plant design, and includes all the applicable performance enhancement and cost reduction features that resulted from the Value Improving Practices (VIP) exercise. The Subtask 1.5A plant design exports about 2850 MW of electric power from about 2,335 TPD (dry) of Illinois No. 6 coal.

The design for the Subtask 1.6 plant will be developed from the Subtask 1.5A plant design as follows:

- Locate the plant at a generic Illinois site.
- Use an advanced cyclone / dry char filter system for particulate removal.
- Change the plant from one to four parallel gasification trains and two gas conditioning trains to produce about 1,250 MW of power. This basis assumes four fully loaded General Electric 7FA+e gas turbines.
- Develop an integrated design for the Balance of Plant (BOP) facilities to take advantage of the economy of scale without a significant loss of availability.

2.0 The Nominal 1,000 MW Coal IGCC Power Plant

2.1 Plant Description

The Nominal 1,000 MW Coal IGCC Power Plant will consist of the following process blocks and subsystems:

- Fuel Handling
- Gasification
  - Slurry Preparation
  - Slag Handling
  - Gasifier / High Temperature Heat Recovery (HTHR)
  - Two-stage Dry Particulate Removal System
  - Low Temperature Heat Recovery (LTHR)
  - Wet Chloride Scrubber
  - Sulfur Removal
  - Sulfur Recovery
- Air Separation Unit (ASU)
- Power Block
  - Gas Turbine (GT) / Heat Recovery Steam Generator (HRSG)
  - Steam Turbine Generator (STG) / Auxiliary Equipment
- Balance of Plant
  - Startup / Backup Fuel System
  - Instrument and Service Air System
  - Cooling Water System
  - Flare System
  - Firewater System
  - Plant Water Intake
  - Water Treatment
  - Waste Water Outfall
  - DCS
  - Switch Yard
  - Plant Roads
  - Buildings
  - Chemical Storage
  - Fence and Security
  - Communication System

A simplified block flow diagram of the nominal 1,000 MW coal IGCC power plant is shown in Figure 1 assuming a four train design. Slag production is not shown. It is estimated that this plant will produce about 1,150 MW of export power from four GE 7FA+e gas turbine / HRSG / steam turbine combinations.

2.2 Feedstock

The feedstock for the coal to power facility will be Illinois No. 6 coal with a maximum sulfur content of 3 wt% on a dry basis. The coal will be delivered to the site by rail and/or by truck.

2.3 Site Selection

The nominal 1,000 MW coal IGCC power plant will be located at a level and cleared generic Illinois site. This site was selected because it is near to both the coal supply and areas of large power consumption.

2.4 Plant Capacity

The plant will process approximately 9,300 TPD of dry coal to generate syngas that will be combusted in four GE 7FA+e gas turbines. The General Electric 7FA+e gas turbine is the most advanced machine that is currently commercially available. This coal rate was selected as the design capacity because it will fully load the four GE 7FA+e gas turbines with syngas.

2.5 Configurations

The design starting point is a single gasification vessel in each train without any spare vessels. The gasifier is Global Energy's two-stage design with slurry quench. It processes about 2,350 TPD of dry coal. The gasifier operating pressure will be about 400 psig. The plant configuration will allow supplemental firing with natural gas to produce power when there is insufficient syngas to fully load all four gas turbines.

2.6 Gasification Area – Four Trains

Each gasification train will contain a slurry preparation area, slurry feed system, gasification reactor, syngas cooler, and syngas particulate removal section. Particulate removal will be by a gas cyclone followed by dry char filters. Steam will be sent to the gas turbine / HRSG train for superheating.

2.7 Gas Conditioning Area – Two Trains

- Syngas Treatment – COS hydrolysis unit
- Acid Gas Removal – Amine type with 99% sulfur removal
- Sulfur Recovery – Claus unit with tail gas recycle to the gasifier

2.8 Air Separation Unit (ASU) – Three Trains

Three non-integrated air separation units will produce oxygen at 95% purity. There will be no nitrogen, oxygen or argon export.

2.9 Power Block

- Gas Turbines – General Electric 7FA+e. Four units, each with a nominal rating of 210 MW. Steam will be used for gas turbine power enhancement and NOx control.

- Steam Turbines – Two units – A reheat, condensing steam turbine will be specified. Turbine power will reflect the steam energy available from the gas turbine / HRSG train.

2.10 Power Output

The export power is expected to be about 1,150 MW. The exact value will be determined based on the above criteria.

3.0 Value Improving Practices

The results of the Value Improving Practices (VIPs), which were be applied to Subtasks 1.3 and 1.4 for performance enhancement, for cost reduction, and to reduce the life-cycle costs (i.e.; increase the Return on Investment (ROI) and Net Present Value (NPV)), will be applied to Subtask 1.6, where applicable.

4.0 Site Conditions

The Subtask 1.6 nominal 1,000 MW coal IGCC power plant will be located at a generic Illinois site having the following properties. (The following properties are those of the Wabash River site, and thus, will be used to represent those at the generic Illinois site.)

Location	Generic Illinois Site
Elevation	500 ft above sea level
Air Temperature	
Maximum, °F	93
Annual Average, °F	59
Minimum, °F	-20
Summer Wet Bulb,°F	70
Relative Humidity, %	60
Barometric Press, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

5.0 Feedstock

The following Illinois No. 6 coal properties will be used for design. These are the same coal properties that were used in Subtasks 1.4 and 1.5.

	Dry Basis	As Received
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,495
Analysis, wt %		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
V & Ni	Nil	Nil
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

6.0 Syngas (Leaving the Sulfur Removal Unit)

The following dry syngas composition leaving the sulfur removal unit is based on preliminary results from Subtask 1.5A.

HHV, Btu/scf (dry)	272
Composition, mole % (dry)	
Carbon Monoxide	47.5
Hydrogen	34.2
Carbon Dioxide	14.7
Nitrogen	1.5
Argon	1.2
Methane	0.9
Total	100

7.0 Electric Power

Export Power, MW	~1,150
Voltage, kV	230

Transmission and substation costs will be included in the plant estimate.

8.0 Water Makeup

Since the nominal 1,000 MW IGCC coal power plant will be located at a generic Illinois site. Specific makeup water properties are unknown. For the purpose of this study, Wabash River water properties will be assumed. Furthermore, it also will be assumed that sufficient makeup water will be available.

Source	River
Supply Pressure, psig	50
Supply Temperature, °F	70

9.0 Natural Gas

The natural gas, which only will be used for startup and backup purposes, will have the following properties.

HHV, Btu/scf	1,000
LHV, Btu/scf	900

10.0 Estimated By-Products Production Rates

The following approximate by-product production rates are based on the estimated coal feed rate. No other by-products will be produced.

Slag, tons/day (@15 wt% water)	1,425
Sulfur, tons/day	240

11.0 Wastes

Waste Water, gpm	TBD
Gas Emissions *	
Particulates	Nil
SOx	> 99% Removal
NOx	<10 ppmvd @15% O_2
CO	< 10 ppmvd

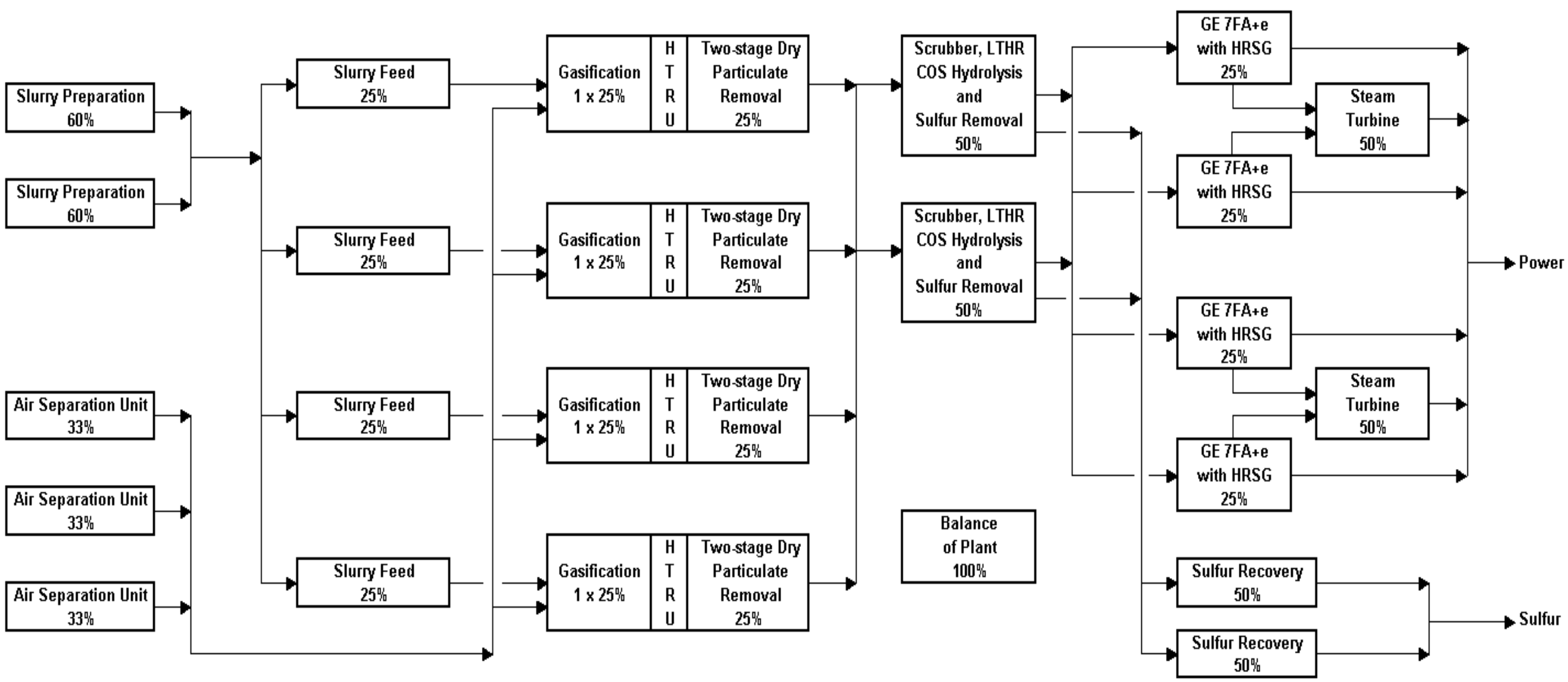
* Based on GE 7FA+e gas turbine data obtained from General Electric.

12.0 Cost Estimate

The process heat and material balances will be used to obtain capacities and equipment sizes for the major process blocks. The cost estimates that were developed for the Optimized Petroleum Coke IGCC Coproduction Plant in Subtask 1.3 will be used as the basis for developing the process block cost estimates. These process block cost estimates will be adjusted, as appropriate, to reflect the design and capacity changes for the nominal 1,000 MW IGCC power plant. The ISBL cost estimate will be developed by combining the costs of the individual ISBL process blocks. The BOP cost estimate will be developed based on the Subtask 1.3 BOP cost estimate except for the makeup water treatment area. The cost for the makeup water treatment area will be based on the Subtask 1.4 facilities since these facilities were designed for Wabash River water and will more accurately represent the required makeup water treatment facilities. Thus, the Total Installed Cost (TIC) estimate for the nominal 1,000 MW coal IGCC power plant will be obtained by combining the ISBL and BOP area costs.

Figure 1

Simplified Block Flow Diagram for the Nominal 1,000 MW Coal IGCC Power Plant



Note: Capacity percentages are based on total plant capacity.

Design Basis for Subtask 1.7

A Coal to Hydrogen Plant

Design Basis for Subtask 1.7
Table of Contents

1.0 Introduction

There has been increasing activities and interest in the use of fuel cells for both transportation fuels and small power generation facilities in the United States. This study will evaluate the merits of a large scale, optimized Coal to Hydrogen Plant located in the mid-west. Besides primarily being used in fuel cells, the product from this plant may also be a low cost source of hydrogen for industrial applications. The gasification section design will be based on the Optimized Single-Train Coal IGCC Plant design developed in Subtask 1.5. The design basis will be based on a gasifier processing about 3,000 TPD of a dry, medium sulfur (~3%) Illinois coal. The results of this study will be used to assess whether coal can penetrate the present day domestic hydrogen, power, or fertilizer market with the current high cost of natural gas.

The objective of Subtask 1.7 is to develop a process design and cost information for a Coal to Hydrogen Plant processing about 3,000 TPD of coal at a generic Illinois site.

This Design Basis (Technical Plan) defines the process units and process support units including the plant configuration required to accomplish the objectives of Subtask 1.7. This plan provides the design basis and basic data for the subsequent engineering study and capital cost estimates. The Coal to Hydrogen Plant will be developed from the Subtask 1.5 case. The Subtask 1.5 case is an Optimized Single-Train Coal IGCC Power Plant located at a generic Mid-Western site. The Subtask 1.5 design includes all the applicable performance enhancement and cost reduction features that resulted from the Value Improving Practices (VIP) exercise. The Subtask 1.7 plant will produce about 140 MMscfd of hydrogen from about 3,000 TPD (dry) of Illinois No. 6 coal.

The Subtask 1.7 plant design will be developed from the Subtask 1.5A coal IGCC power plant design as follows:

- Enlarge the gasifier to process about 3,000 TPD (dry) of coal, the same amount of coal that the Subtask 1.4 gasifier processes.
- Remove the gas turbine / HRSG facilities.
- Add dry particulate removal / filtration
- Add hydrogen production, purification (Rectisol H_2S and CO_2 removal, PSA, and drying), and compression facilities.
- Resize the steam boiler to consume all available fuel gas to superheat steam for power production in a condensing steam turbine.
- Redesign the Balance of Plant (BOP) facilities for this case.

2.0 The Coal to Hydrogen Plant

2.1 Plant Description

The Coal to Hydrogen Plant will consist of the following process blocks and subsystems:

- Fuel Handling

- Gasification
    - Slurry Preparation
    - Slag Handling
    - Gasifier / High Temperature Heat Recovery (HTHR)
    - Dry Particulate Removal System
    - Wet Scrubber System (chloride removal)
    - Sulfur Removal (Rectisol)
    - Sulfur Recovery

- Air Separation Unit (ASU)

- Hydrogen Production
    - CO Shift
    - CO_2 Removal (Rectisol)
    - Pressure Swing Adsorption (PSA)
    - Drying
    - Hydrogen Compression

- Power Block
    - Incinerator Heat Recovery / Steam Superheater
    - Steam Turbine Generator (STG) / Auxiliary Equipment

- Balance of Plant
    - Startup / Backup Fuel System
    - Instrument and Service Air System
    - Cooling Water System
    - Flare System
    - Firewater System
    - Plant Water Intake
    - Water Treatment
    - Waste Water Outfall
    - DCS
    - Switch Yard
    - Plant Roads
    - Buildings
    - Chemical Storage
    - Fence and Security
    - Communication System

It is estimated that this plant will produce about 140 MMscfd of 99+% hydrogen at 1,000 psia.

Figure 1 shows a simplified block flow diagram of the Coal to Hydrogen Plant. This is a single train plant except for hydrogen production and purification. Figure 1 shows only two parallel hydrogen production and purification plant trains.

2.2 Feedstock

The feedstock for the coal to power facility will be Illinois No. 6 coal with a maximum sulfur content of 3 wt% on a dry basis. The coal will be delivered to the site by rail and/or by truck.

2.3 Site Selection

The Coal to Hydrogen Plant will be located at a level and cleared generic Illinois site. This site was selected because it is near to both the coal supply and population and industrial centers.

2.4 Plant Capacity

The plant will process approximately 3,000 TPD of dry coal to generate syngas that will be reacted to produce hydrogen in the CO shift reactors.

2.5 Configurations

The design starting point is the single Subtask 1.5 gasification vessel. The gasifier will be Global Energy's two-stage design with slurry quench. The gasifier operating pressure will be about 400 psig.

2.6 Gasification Area

Syngas Cooler and Syngas Particulate Removal – Saturated 1,500 psig steam for power production. Particulate removal will be by a gas cyclone followed by dry particulate filters.

2.7 Gas Conditioning Area

- Syngas Treatment Units - Chloride scrubber
- Acid Gas Removal - Rectisol type with 99+% sulfur removal (<1 ppm)
- Sulfur Recovery - Claus unit with tail gas recycle to the gasifier

2.8 Air Separation Unit (ASU)

One air separation unit producing 99.5% oxygen. There will be no argon export.

2.9 Hydrogen Production

Capacity – About 140 MMscfd
H2 Purity – 99.0% minimum with CO less than 10 ppm, and sulfur less than 1 ppm.
H2 Delivery Pressure – 1,000 psig
Process Units – CO Shift (HT/LT), Rectisol H_2S and CO_2 removal, Pressure Swing Adsorption (PSA), and drying units.

2.10 Power Block

Steam Turbine - A condensing steam turbine will be specified. Turbine power will reflect the steam energy available from the superheated steam produced in the PSA tail gas combustor / steam boiler. Process steam will be provided by extraction from the steam turbine.

2.11 Power Output

It is likely that the plant will import power.

3.0 Value Improving Practices

The results of the Value Improving Practices (VIPs), which were be applied to Subtasks 1.3 and 1.5 for performance enhancement, for cost reduction, and to reduce the life-cycle costs (i.e.; increase the Return on Investment (ROI) and Net Present Value, (NPV)), will be applied to Subtask 1.7, where applicable.

4.0 Site Conditions

The Subtask 1.7 Coal to Hydrogen Plant will be located at a generic Illinois site having the following properties. (The following properties are those of the Wabash River site, and thus, will be used to represent those at the generic Illinois site.)

Location	Generic Illinois Site
Elevation	500 ft above sea level
Air Temperature	
Maximum, °F	93
Annual Avg, °F	59
Minimum, °F	-20
Summer Wet Bulb,°F	70
Relative Humidity, %	60
Barometric Press, psia	14.43
Seismic Zone	2B
Design Wind Speed, MPH	70

5.0 Feedstock

The following Illinois No. 6 coal properties will be used for design. These are the same coal properties that were used in Subtasks 1.4, 1.5, and 1.6.

	Dry Basis	As Received
HHV, Btu/lb	12,749	10,900
LHV, Btu/lb	12,275	10,495
Analysis, wt %		
Carbon	70.02	59.87
Hydrogen	4.99	4.27
Nitrogen	1.30	1.11
Sulfur	2.58	2.21
Oxygen	8.27	7.07
Chlorine	0.13	0.11
V & Ni	Nil	Nil
Ash	12.70	10.86
Moisture	NA	14.50
Total	100	100

6.0 Syngas (Leaving the Sulfur Removal Unit)

The following dry syngas composition leaving the sulfur removal unit is based on preliminary results from Subtask 1.5.

HHV, Btu/scf (dry)	275
Composition, mole % (dry)	
Carbon Monoxide	46.8
Hydrogen	33.3
Carbon Dioxide	14.8
Nitrogen	1.6
Argon	1.2
Methane	2.3
Total	100

7.0 Electric Power

The plant probably will need to import power. However, the design will determine whether the plant will either be in power balance, import power, or export power. Appropriate transmission and substation costs will be included in the plant cost estimate.

8.0 Water Makeup

Since the Coal to Hydrogen Plant will be located at a generic Illinois site. Specific makeup water properties are unknown. For the purpose of this study, Wabash River water properties will be assumed. Furthermore, it also will be assumed that sufficient makeup water will be available.

Source	River
Supply Pressure, psig	50
Supply Temperature, °F	70

9.0 Natural Gas

The natural gas, which only will be used for startup and backup purposes, will have the following properties.

HHV, Btu/scf	1000
LHV, Btu/scf	900

10.0 Estimated By-Products Production Rates

The following approximate by-product production rates are based on the estimated coal feed rate. No other by-products will be produced.

Slag, tons/day (@15 wt% water)	480
Sulfur, tons/day	78

11.0 Wastes

On the process side, this will be a zero discharge plant. Cooling tower and steam system blowdown water will be discharged.

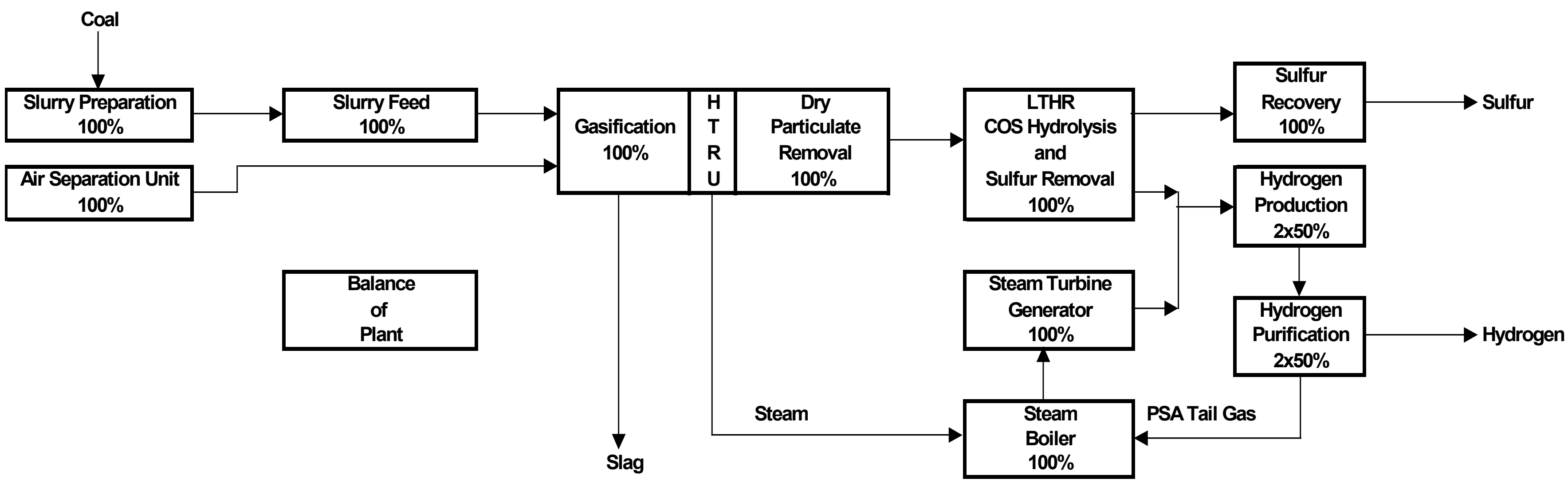
Waste Water, gpm	TBD
Incinerator Gas Emissions	
Particulates	Nil
SOx	> 99% Removal
NOx, ppmvd	40
CO, ppmvd	50

12.0 Cost Estimate

The detailed process simulation model that was developed for Subtask 1.5, the Optimized Single-Train Coal IGCC Power Plant, will be modified to reflect the effect of higher purity oxygen in the gasifier. The model results will be used to obtain capacities and equipment sizes for the major process blocks. The cost estimates that were developed for the Optimized Single-Train Coal IGCC Power Plant in Subtasks 1.5 or 1.6 will be used as the basis for developing the process block cost estimates. These process block cost estimates will be adjusted, as appropriate, to reflect the design changes. The cost of the hydrogen production facilities will be prorated from Subtask 1.3, the Optimized Petroleum Coke IGCC Coproduction Plant. The ISBL cost estimate will be developed by combining the individual ISBL process block costs. The BOP (balance of plant) cost estimate will be developed based on the Subtask 1.5 or 1.6 BOP cost estimate and adjusted, as appropriate. Thus, the Total Installed Cost (TIC) estimate for the Coal to Hydrogen Plant will be obtained by combining the ISBL and BOP area costs.

Figure 1

Simplified Block Flow Diagram for the Coal to Hydrogen Plant



Appendix L

Technical Publications

Appendix L

Technical Publications

As of the publication date of this report, this study has produced two technical presentations. They were:

1. Amick, P., Geosits, R., Kramer, S., Rockey, J., and Tam, S., "IGCC Plant Performance & Cost Optimization Study", Seventeenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA, September 11-15, 2000.

2. Amick, P., Geosits, R., Herbanek, R., Kramer, S., Rockey, J., and Tam, S., "An Optimized Petroleum Coke IGCC Coproduction Plant", Gasification Technologies Council Conference, San Francisco, CA, October 7-10, 2001.

Copies of these papers follow.

IGCC Plant Performance & Cost Optimization Study

for presentation at the
Seventeenth Annual International
Pittsburgh Coal Conference
September 11-15, 2000

Phil Amick, Global Energy, Inc.
Robert Geosits, Bechtel Corporation
Sheldon Kramer, Nexant, Inc.
John Rockey, NETL
Samuel Tam, Nexant, Inc.

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy (DOE) to promote energy production from fossil fuels in the 21st century. It will integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. It will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 includes plans to give integrated gasification combined cycle (IGCC) systems a major role for the continued use of solid fossil fuels. Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly to build and operate. The goal of this study is to improve the net present value (NPV) of gasification projects by optimizing plant performance, capital cost, and operating costs. The key benefit of doing this methodical cost optimization process off-line is that it removes the schedule constraints associated with project development that tend to inhibit innovation and implementation of new ideas.

In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel Technology & Consulting Company) and Global Energy, Inc. (which recently acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the Destec Gasification Process) a contract to optimize IGCC plant performance.[1] Task 1 of this contract will optimize two IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Task 2 will optimize two different IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of liquid transportation fuels, and (2) coal gasification for electric power with the coproduction of liquid transportation fuels. Task 3 will develop conceptual designs and projected costs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

---

[1] Contract No. DE-AC26-99FT40342, "Gasification Plant Cost and Performance Optimization"

This paper reports on the progress of this study, the interim results for Task 1, and the approach being taken to optimize the IGCC plants.

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[2] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrates a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[3] However, the first year of operation resulted in only a 20% capacity factor, with over one half of the outage time being attributable to the dry char particulate removal system where frequent failures of the ceramic candle filters were experienced. The facility has switched to operation with metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility for the site. Additionally, two successful tests using petroleum coke including one from a refinery processing Mayan crude were completed in November, 1997 and

---

[2] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"

[3] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November, 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.

September, 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria. The results of the petroleum coke tests have been previously described.[4]

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.999 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing). The repowering project has demonstrated the ability to run at full load capability (250 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the Project, with a demonstrated heat rate of under 9,000 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-Gas Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

The Wabash River Greenfield Project Plant

The gasification optimization work began with reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that Wabash River project design was transformed into a greenfield IGCC design as shown in Step 1 of Figure 1. In Step 2, the coal plant was converted to a trigeneration facility using petroleum coke as fuel and producing electricity, hydrogen, and industrial-grade steam. The paths to optimize the coal and petroleum coke fed plants are Steps 3 and 4 in the figure.

Since one major focus of this study is the optimization of the gasification plant costs, the following three-stage cost estimating methodology was employed to develop a current year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal

[4] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project, were adjusted for unusual circumstances and escalated to today's values. The costs of any equipment and materials that were not part of the Wabash River project (such as existing facilities), but are required, were added the cost database.
- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Major pieces of equipment that required modifications during the demonstration period were incorporated, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. Bechtel's Multi-Project Acquisition Group (MPAG) worked with manufacturers, fabricators, and suppliers with whom current procurement agreements have been established to provide the most cost-effective pricing. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities to provide a basis for evaluating future changes. This tool enables the study team to make changes in plot plan layout, process improvements, equipment sizes, structural support, etc. and determine the effect on the bulk material requirements.
- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Further evaluation of gasification technologies and other energy related process plants require a standard methodology for estimating the capital costs. The format for this estimating tool based on historical data, escalation indices and vendor quotes was developed and will be employed on subsequent tasks in this study and for future project development activities.

Figure 2 is a block flow diagram showing the major process blocks in the Wabash River Project Greenfield Plant developed in Step 1. The major design and operating conditions for the plant are shown in Table 1.

The Petroleum Coke IGCC Coproduction Plant

Since present-day gasification applications are more likely to be based on petroleum coke due to its low fuel value cost, in Step 2 the stand-alone coal-based Wabash River Greenfield Project Plant was reconfigured to use coke and produce power and hydrogen for an adjacent petroleum refinery; i. e., to be a trigeneration plant. Gasifier performance on petroleum coke is based on the recent successful coke runs at the actual Wabash River project facility.

Thus, following the above greenfield plant and location adjustments of Step 1, the plant was enlarged and re-engineered to process petroleum coke, rather than coal, and produce hydrogen and industrial-grade steam in addition to electric power. This plant is located at a generic U. S. Gulf Coast site adjacent to a large petroleum refinery. Because it becomes an integral part of the petroleum refinery by supplying 79 MMscfd of high-purity hydrogen and 980,000 lb/hr of 700 psig/750^{o}F steam to the petroleum processing units, it must be highly reliable since unexpected outages can have severe economic consequences to the refinery operations. Because of this reliability requirement, many units and/or portions of units, were spared to maximize plant reliability.

Figure 3 is a block flow diagram showing the major process blocks in the Petroleum Coke IGCC Coproduction Plant developed in Step 2. The major operating conditions for the petroleum coke fed plant also are shown in Table 1.

The Optimization Process

Steps 1 and 2 are essentially complete. The next step (ongoing) is to optimize the petroleum coke IGCC plant. Process and project optimization is guided by Bechtel's Value Improvement Practices (VIPs) methodology. Bechtel and Global Energy are using the following VIPs on this study:

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Process Reliability Modeling
- Design-to-Capacity
- Energy Optimization
- Predictive Maintenance
- Traditional Value Engineering
- Schedule Optimization
- Constructability

Initially, Bechtel and Global Energy prepared a Value Improvement Plan. This plan determined that the above practices are most applicable to this study. "Champions" were assigned to each applicable practice, and those champions along with the Value Improvement Plan administrator are responsible for the implementation of the VIP process as well as documenting the results. Bechtel and Global Energy currently are analyzing the Value Engineering ideas generated during the brainstorming sessions to determine which are applicable for improving the NPV of the project and quantifying the benefits of these improvements.

We are concentrating our VIP efforts in the gasification area, specifically on the gasification and waste heat recovery section, the particulate removal section, and the raw gas cooling area. Lessons learned from plant operations showed that these areas are critical to reliable operations and high on-stream factors. In the Traditional Value Engineering VIP, almost 300 different ideas were generated in several brainstorming sessions. These ideas are based on (1) actual operations and maintenance experience at the Wabash River plant, (2) the EPC of the Wabash River Repowering Project, and (3) Bechtel's EPC experience in other gasification projects with similar equipment. The personnel operating at the Wabash River facility generated many of these ideas.

In conjunction with the Value Improvement Plan, Bechtel is using the COMET program to evaluate and optimize equipment layout arrangements to minimize the piping requirements for a given area or between areas. By changing the location of any equipment item in a given area, COMET will readjust the piping between the equipment and recalculate a new quantity of piping. This optimization tool is especially beneficial where a lot of large bore or high cost alloy piping is used. Additionally, the COMET program also is capable of automatically generating plot plans and architectural renderings of the plant.

For several years now, Bechtel has been conducting optimizing evaluations in the heat integration of their standard coal and gas-based power plant designs. Bechtel has developed a *Powerline* suite of templates for combined cycle, pulverized coal, and fluidized bed power plant designs. These *Powerline* plants incorporate the most advanced technologies and best practices from Bechtel's engineering portfolio. Designing plants using standard templates saves engineering and procurement costs resulting in better plants that are less expensive and require less time for construction. The lessons learned during the development of the *Powerline* templates also are being applied in Steps 3 and 4 to optimize the designs.

Bechtel has created a number of supplier alliances, not only for major equipment manufacture and fabrication, but also for construction materials. In addition to reducing the price of equipment, these alliances also shorten the engineering and procurement cycle resulting in a shorter overall project schedule and reduced EPC costs. Shorter schedules and reduced EPC costs translate into faster payback and increased profitability. These ideas also will be applied to the optimized designs.

Discounted Cash Flow Analysis

Progress in optimizing IGCC plant designs, performance, and costs will be measured in terms of improved project net present values using a discounted cash flow model previously developed by Nexant (formerly Bechtel Technology and Consulting) for the DOE to evaluate IGCC projects.[5] This financial model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of various IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) projects summary result sheets.

Other useful economic measures, besides NPV, that the discounted cash flow model generates include the internal rate of return at a given price structure, the benefit to cost

[5] Contract No. DE-AM01-98FE64778, "IGCC Economic and Capital Budgeting Evaluation"

ratio, the payback period on equity, and the required electricity price to support a given internal rate of return.

Project Status

At present, Steps 1 and 2 have been completed. Detailed heat and material balances are available. Optimization of the plant designs in Steps 3 and 4 is proceeding nicely. Although the results look promising, it is still too early in the process to quantify the benefits. Steps 3 and 4 should be completed by early next year, and a Topical Report detailing the results will be submitted to the Department of Energy by the end of the first quarter.

A detailed construction cost data base has been developed to support future project development needs. It includes Wabash River cost data with appropriate escalation indices, current equipment and bulks cost data, and *Powerline* combined cycle cost data. Basing the data on the Wabash River Coal Gasification Repowering Project gives the cost information a high degree of accuracy, about +/- 10%. Building on this information, the optimized plant cost also should have a narrow accuracy range; i.e., have a high degree of confidence. Similarly, the expected operating and maintenance costs will be reliable since they are an extrapolation of Wabash River experience.

Summary

Based on the greenfield gasification plant design and cost estimate, advanced methods of engineering and cost control are being employed to improve the plant design, increase operating efficiencies, reduce costs, and increase project NPVs of future IGCC plants. Nexant and Global Energy also will evaluate more long-term gasification options with the potential for even cleaner, more efficient, and lower cost plants than are currently possible with available equipment.

Table 1
Plant Design and Operating Conditions

	Wabash River Greenfield Project Plant		Petroleum Coke IGCC Coproduction Plant	
Location	Typical Mid-Western State		U.S. Gulf Coast near a Petroleum Refinery	
Feedstock	Illinois No. 6 Coal		Green Delayed Petroleum Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	13,810
Analysis, wt %				
Carbon	69.9	59.76	88.76	82.55
Hydrogen	5.0	4.28	3.20	2.98
Nitrogen	1.3	1.11	0.90	0.84
Sulfur	2.58	2.21	7.00	6.51
Oxygen	8.27	7.07	-	-
Chlorine	0.13	0.11	50 ppm	47 ppm
V & Ni	-	-	1900 ppm	1767 ppm
Ash	12.7	10.86	0.14	0.13
Moisture	-	14.5	-	6.99
Total	100	100	100	100
Inputs				
Fuel, dry basis	2,260 tons/day		5,250 tons/day	
Makeup Water,	2,800 gpm		4,800 gpm	
Refinery Condensate	0		686,000 lb/hr	
Outputs				
Export Power, MW	270		396	
Slag, tons/day	356		190	
Sulfur, tons/day	57		367	
Hydrogen	0		79 MMscfd	
Purity	-		99 %	
Pressure	-		1000 psig	
Temperature	-		$120^{o}F$	
Steam	0		980,000 lb/hr	
Pressure	-		700 psig	
Temperature	-		$750^{o}F$	
Waste Water	120 gpm		30 gpm	
Gas Emissions				
Particulates	Nil		Nil	
SOx, as SO_2	240 lb/hr (<0.1 lb/MMBtu)		> 99.5 % Removal	
NOx, as NO_2	152 lb/hr (<25 ppmvd)		< 25 ppmvd	
CO	120 lb/hr		< 15 ppmvd	

Figure 1

Steps for Optimization of the Coal IGCC Design

and the Petroleum Coke-IGCC Coproduction Plant

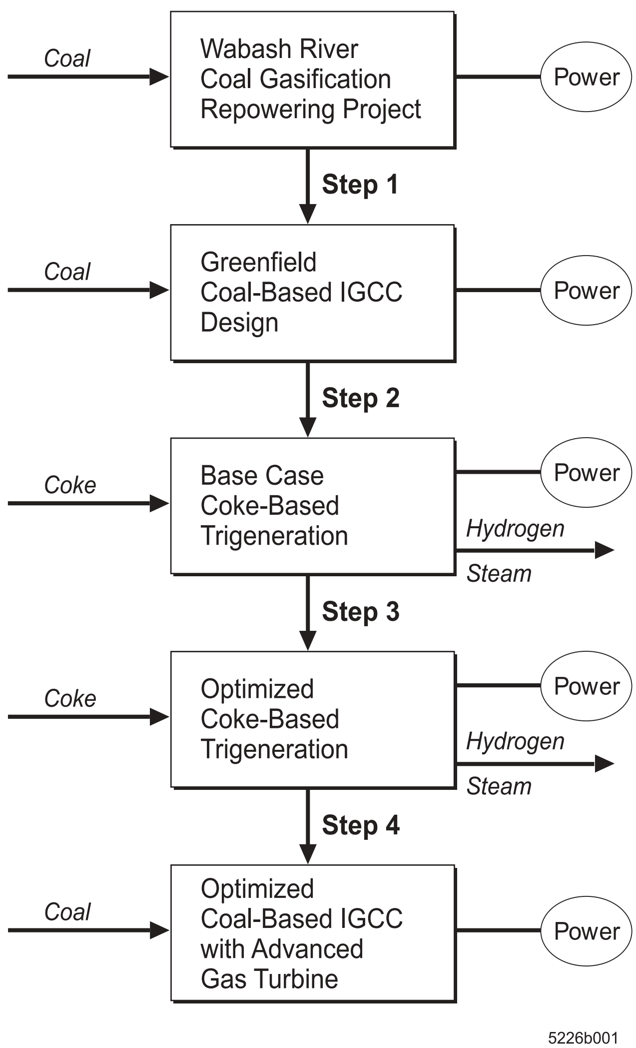


Figure 2

WABASH RIVER PROJECT GREENFIELD PLANT BLOCK FLOW DIAGRAM

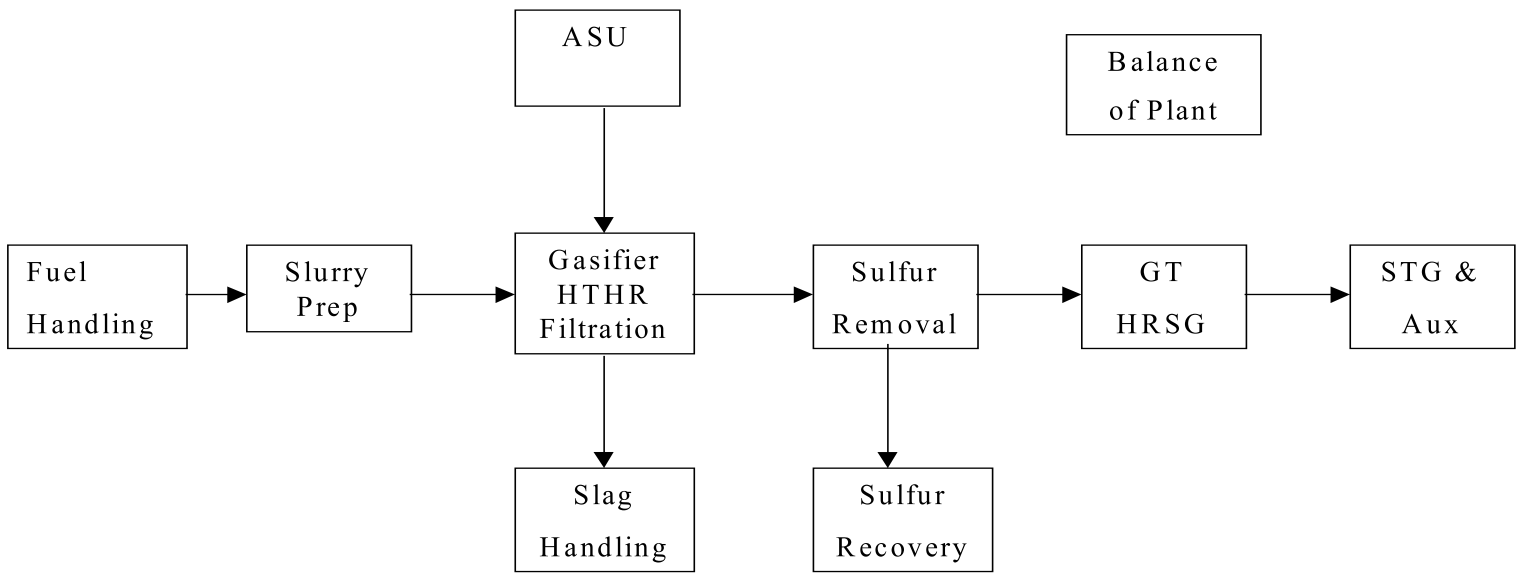
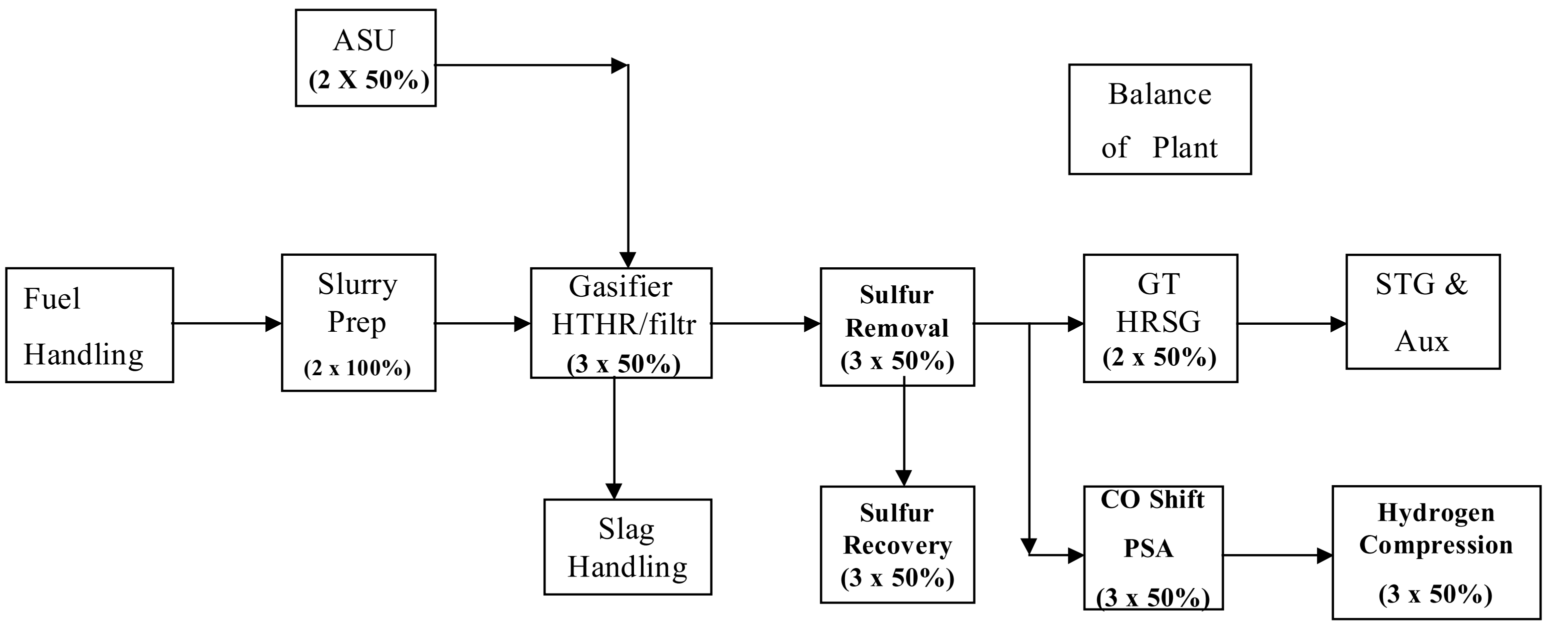


Figure 3
PETROLEUM COKE IGCC COPRODUCTION PLANT BLOCK FLOW DIAGRAM



An Optimized Petroleum Coke IGCC Coproduction Plant

for presentation at the
Gasification Technologies Council Conference
San Francisco, California
October 7-10, 2001

Phil Amick, Global Energy, Inc.
Robert Geosits, Bechtel Corporation
Ron Herbanek, Global Energy, Inc.
Sheldon Kramer, Nexant, Inc.
John Rockey, NETL
Samuel Tam, Nexant, Inc.

The *Vision 21* concept is the approach being developed by the U. S. Department of Energy (DOE) to promote energy production from fossil fuels in the 21st century. It will integrate advanced concepts for high efficiency power generation and pollution control into a new class of fuel-flexible facilities capable of coproducing electric power, process heat, high value fuels, and chemicals with virtually no emissions of air pollutants. It will be capable of a variety of configurations to meet different marketing needs, including both distributed and central power generation.

Vision 21 includes plans to give integrated gasification combined cycle (IGCC) systems a major role for the continued use of solid fossil fuels. Gasification systems are inherently clean, relatively efficient, and commercially available for converting inexpensive fuels such as coal and petroleum coke into electric power, steam, hydrogen, and chemicals. However, the gasification system also is relatively complex and costly to build and operate. The goal of this study is to improve the profitability of gasification projects by optimizing plant performance, capital cost, and operating costs. The key benefit of doing this methodical cost optimization process off-line is that it removes the schedule constraints associated with project development that tend to inhibit innovation and implementation of new ideas.

In late 1999, the National Energy Technology Laboratory awarded Nexant Inc. (a Bechtel Technology & Consulting Company) and Global Energy, Inc. (which acquired the gasification related assets of Dynegy Inc., of Houston, Texas including the E-Gas gasification technology, formerly the Destec Gasification Process) a contract to optimize IGCC plant performance.[1] Task 1 of this contract developed two optimized IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of hydrogen and industrial-grade steam, and (2) coal gasification for electric power generation only. Task 2 will optimize two different IGCC plant configurations: (1) petroleum coke gasification for electric power with the coproduction of liquid transportation fuels, and (2) coal gasification for electric power with the coproduction of liquid transportation fuels. Task 3 will develop conceptual designs and projected costs for advanced gasification plants including the integration with fuel cells and/or the addition of carbon dioxide control technologies.

This paper describes the optimization and cost reduction techniques used, presents the optimized designs, and summarizes plant performance for the petroleum coke IGCC coproduction plant. It also provides cost information and presents a financial analysis. Finally, based on recent Wabash River operating experience, the potential for further design enhancements, cost reductions, performance improvements, and market penetration is discussed.

[1] Contract No. DE-AC26-99FT40342, “Gasification Plant Cost and Performance Optimization”

The Wabash River Coal Gasification Repowering Project

In 1990, Destec Energy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana formed the Wabash River Coal Gasification Repowering Project Joint Venture to participate in the Department of Energy's Clean Coal Technology Program by demonstrating the coal gasification repowering of an existing 1950's vintage generating unit. In September 1991, the project was selected by the DOE as a Clean Coal Round IV project to demonstrate the integration of the existing PSI steam turbine generator and auxiliaries, a new combustion turbine, a heat recovery steam generator, and a coal gasification facility to achieve improved efficiency and reduced emissions. In July 1992, a Cooperative Agreement was signed with the DOE.[2] Under terms of this agreement, the Wabash River Coal Gasification Repowering Project Joint Venture developed, constructed and operated the coal gasification combined cycle facility. The DOE provided cost-sharing funds for construction and a three-year demonstration period.

The participants jointly developed, separately designed, constructed, owned, and operated the integrated coal gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The gasification process integrates a new General Electric 7FA combustion turbine generator and a heat recovery steam generator (HRSG) to repower the 1950s-vintage Westinghouse steam turbine generator using some of the pre-existing coal handling facilities, interconnections, and other auxiliaries.

Commercial operation of the facility began late in 1995. Within a few months, both the gasification and combined-cycle plants successfully demonstrated the ability to run at capacity and within environmental compliance while using locally mined high sulfur Illinois Basin bituminous coal.[3] However, the first year of operation resulted in only a 35% annual availability, with over one half of the outage time being attributable to the dry char particulate removal system which experienced frequent failures of the ceramic candle filters. The facility has modified the particulate removal system including the use of metallic filters and has made significant improvements in other areas such as COS catalyst durability, chloride removal, and ash deposition control. As a result, step improvements in production were made during the second and third years of commercial operation. During the third year, operations were demonstrated on a second coal feedstock as well as a blend of two different Illinois No. 6 coals. This ability to blend coal feedstocks has improved the fuel flexibility for the site. Additionally, two successful tests using petroleum coke (including one from a refinery processing Mayan crude) were completed in November 1997 and September 1999 further demonstrating the fuel flexibility of the technology. At operational rates of about 2,000 TPD of petroleum coke, over 250 MW of power was generated from the gas turbine combined cycle power plant while meeting all emission criteria. The results of the petroleum coke tests have been previously described.[4]

The gasification facility also produces two commercial by-products. Sulfur is removed as 99.99 percent pure elemental sulfur and sold to sulfur users. Slag is being marketed for use as an aggregate in asphalt roads, as structural fill in various types of construction applications, as roofing granules, and as blasting grit.

---

[2] Contract No. DE-FC21-92MC9310, "Wabash River Coal Gasification Repowering Project"
[3] Topical Report Number 7, "The Wabash River Coal Gasification Repowering Project," Contract No. DE-FC21-92MC9310, November, 1996, http://www.netl.doe.gov/publications/others/topicals/topical7.pdf.
[4] Phil Amick, *Commercial Operation of the Wabash River Gasification Project,* AIChE Spring National Meeting, Session T9011, New Orleans, March 9, 2000.

In 1998, the plant surpassed milestones of 10,000 hours of coal operation, 1,000,000 tons of coal processed, and achieved 77% availability for the third year of commercial operations (excluding downtime attributed to the combined cycle power generation section and for alternative fuel testing).[5] Since Spring 2000, the plant has been fueled by delayed petroleum coke and has been operating with minimal problems and significantly improved on-stream performance.

The repowering project demonstrated the ability to run at full load capability (262 MW) while meeting the environmental requirements for sulfur and NOx emissions. Cinergy, PSI's parent company, dispatches power from the Project with a demonstrated heat rate of 8,900 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Currently, the Wabash River Coal Gasification Repowering Project is the largest single train gasification facility in the Western Hemisphere, as well as the cleanest coal fired plant of any kind in the world. Global Energy now owns and operates the facility, and has renamed the Destec Gasification Process as the E-GAS™ Technology for future applications.

Based on the Wabash River Coal Gasification Repowering Project, Global Energy, Bechtel and Nexant are contributing their combined design, engineering, construction, and operating expertise to develop optimized designs for state-of-the-art IGCC plants processing either coal or petroleum coke.

The Wabash River Greenfield Project Plant

The gasification optimization work began with reviewing and assessing data from the existing Wabash River Project facility. Using the existing plant as the basis, design and cost engineers adjusted the plant's scope – equipment, materials, and process operation – so that the Wabash River project design was transformed into a greenfield IGCC design as shown in Step 1 of Figure 1. In Step 2, the coal plant was converted to a trigeneration facility using petroleum coke as fuel and producing electricity, hydrogen, and industrial-grade steam. The paths to optimize the coal and petroleum coke plants are Steps 3 and 4 in the figure.

Figure 2 is a simplified block flow diagram showing the major process blocks in the Wabash River Project Greenfield Plant developed in Step 1. Table 1 shows the coal properties and the major feed and product rates for the plant.

Capital cost is a key part of IGCC economics and profitability. The following three-stage cost estimating methodology was employed to develop a mid-year 2000 total installed cost for a greenfield plant equivalent to the Wabash River Coal Gasification Repowering Project, but located at a generic site in a typical Mid-Western state.

- **Derive a Cost Database from the Existing Wabash River Project Facility.** The initial cost database was set up using the documented equipment and construction material prices from the Wabash River Coal Gasification Repowering Project. The actual costs from the project were adjusted to eliminate the impact of unusual circumstances and escalated to today's values. The costs of any required equipment and materials that were not part of the new scope (such as the existing facilities; i. e., the repowered steam turbine), were added to the cost database.

[5] "Wabash River Coal Gasification Repowering Project, Final Technical Report", U. S. Department of Energy, Contract Agreement DE-FC21-92MC29310, http://www.lanl.gov/projects/cctc/resources/pdfs/wabsh/Final%20_Report.pdf, August 2000.

- **Evaluate Changes and Incorporate the Effects of Changes into the Capital and Operating Costs.** Modifications to major pieces of equipment required during the demonstration period were considered, and, if necessary, new cost quotes were obtained. One example of this is the previously mentioned change from ceramic candle filters to metallic ones. The Bechtel estimating tool, COMET, was used to benchmark the bulk material quantities and to provide a basis for evaluating future changes. This tool enabled the study team to alter the plant layout as a result of process improvements, equipment size changes, etc., and to determine the net effect on piping and other bulk material quantities.

- **Develop a Method for Adjusting Base Case Capital Costs to Estimate Other Design Configurations.** Evaluations of alternate plant configurations required a standard methodology for estimating the resulting capital costs. The format for this estimating tool was developed based on historical data, escalation indices and vendor quotes and will be employed on subsequent tasks in this study and for future project development activities.

The Non-optimized Petroleum Coke IGCC Coproduction Plant

The present-day market for solid feed gasification applications appears to be directed toward the use of low value fuels such as petroleum coke. In Step 2 the stand-alone coal-based Wabash River Greenfield Project Plant was reconfigured to use coke and produce power, steam, and hydrogen for an adjacent petroleum refinery and was moved to the Gulf Coast. Gasifier performance on petroleum coke is based on the current petroleum coke operations at the Wabash River facility.

The basis for the design of the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant was that the steam and hydrogen products that it produces must have a high reliability and can be sold to the adjacent petroleum refinery. Because a single gasification train with backup natural gas firing can satisfy the refinery steam and hydrogen requirements by sacrificing electric power production, all critical parts of the plant were replicated to provide high reliability of a single gasification train. For example, the slurry preparation and slurry storage contain two duplicate 100% trains each with sufficient capacity for the entire plant. The entire gasification area from the slurry pumping and heating sections to the acid gas removal area, including the sulfur recovery facilities, and hydrogen production facilities consist of three duplicate trains each with a capacity of 50% of the total plant design capacity. Figure 3 is a simplified block flow diagram of the non-optimized plant showing the major processing areas and major process streams between processing areas. The processing functions in the balance of plant area, such as makeup water treatment, are not shown. Figure 4 is a train diagram of the plant showing the replication of the major plant sections.

Because this plant now becomes an integral part of the petroleum refinery by supplying high-purity hydrogen and steam to the petroleum processing units, it must be highly reliable since unexpected outages can have severe economic consequences to the refinery operations. This high degree of sparing (100% capacity when any one unit is down) and reliability is typical of today's petroleum coke IGCC coproduction plant market.

Thus, based on the greenfield plant of Step 1 and location adjustments, the plant was enlarged and re-engineered to process petroleum coke, rather than coal, to produce hydrogen and industrial-grade steam in addition to electric power from two base loaded GE 7FA combustion turbines.. This plant is located at a generic U. S. Gulf Coast site adjacent to a large petroleum refinery. The plant consumes 5,249 TPD of dry petroleum coke and produces 395.8 MW of export electric power, 79.4 MMscfd of hydrogen, 980,000 lb/hr of 700 psig/750^{o}F steam, and 367 TPD of sulfur. It also produces 99.6 MMscfd of a low

Btu fuel gas (87 Btu/scf HHV) for sale to the adjacent petroleum refinery. Table 1 shows the coke properties and the major design and operating conditions for the non-optimized petroleum coke IGCC coproduction plant.

The Subtask 1.2 plant uses two GE 7FA gas turbines; the same gas turbine as used at the Wabash River facility. A current, more efficient steam turbine that was optimized for this application was used rather than the 1953 vintage steam turbine that was repowered at Wabash River. New petroleum coke receiving and storage facilities were designed to replace the coal facilities since the Wabash River Repowering Project used the existing facilities. New fresh water treatment facilities, a cooling water recirculation loop, and a cooling tower were added to replace the once through cooling water system. New waste water cleanup facilities also were designed to allow compliance with water discharge criteria and commingling of waster water with the refinery waste water outfall.

The mid-year 2000 installed cost of the non-optimized petroleum coke IGCC plant is 993.2 MM$. All installed plant costs cited in this paper are EPC costs which exclude contingency, taxes, licensing fees, and owners costs (such as land, operating and maintenance equipment, capital spares, operator training, and commercial test runs).[6] They also assume that process effluent discharges are permitted.

The Optimization Process

After Steps 1 and 2 were completed, the next step was to optimize the petroleum coke IGCC plant. Process and project optimization was guided by Bechtel's Value Improvement Practices (VIPs) methodology using the following VIPs:

- Technology Selection
- Process Simplification
- Classes of Plant Quality
- Process Reliability Modeling
- Design-to-Capacity
- Predictive Maintenance
- Traditional Value Engineering
- Constructability and Schedule Optimization

Initially, Bechtel and Global Energy prepared a Value Improvement Plan. This plan determined that the above practices were most applicable to this study. "Champions" were assigned to each applicable practice, and those champions along with the Value Improvement Plan administrator were responsible for implementation of the VIP process as well as documenting the results. Bechtel and Global Energy thoroughly analyzed the Value Engineering ideas generated during the brainstorming sessions to determine which were applicable for improving the project by assessing their benefits.

The VIP efforts were concentrated in the gasification area, specifically on the gasification and waste heat recovery section, the particulate removal section, the raw gas cooling area, and the syngas cleanup area. Lessons learned from plant operations showed that these areas are critical to reliable operations and high on-stream factors. In the Traditional Value Engineering VIP, almost 300 different ideas were generated in several brainstorming sessions. These ideas are based on (1) actual operations and maintenance experience at the Wabash River plant, (2) the construction of the Wabash River Repowering Project, and (3) Bechtel's experience in other gasification and power generation projects with similar equipment. Operating personnel from the Wabash River facility proposed many of these ideas.

[6] These excluded items are included in the subsequent discounted cash flow financial analysis.

In conjunction with the Value Improvement Plan, Bechtel used the COMET plant layout program to evaluate and optimize equipment layout arrangements and minimize the piping requirements for a given area or between areas. By changing the location of any equipment item in a given area, COMET readjusts the interconnecting piping and recalculates new quantities. This optimization tool is especially beneficial in cases where a large percentage of the piping is large bore or high cost alloy material. Additionally, the COMET program also is capable of automatically generating plot plans and three-dimensional architectural renderings of the plant.

For several years now, Bechtel has been optimizing the heat integration of their standard coal and gas-based power plant designs. As a consequence, Bechtel has developed a *Powerline* suite of templates for combined cycle, pulverized coal, and fluidized bed power plant designs.[7] These *Powerline* plants incorporate the most advanced technologies and best practices from Bechtel's engineering portfolio. Designing plants using standard templates saves engineering and procurement costs resulting in higher quality plants that are less expensive and require less time for construction. The lessons learned during the development of the *Powerline* templates also were applied to optimize the designs for the various subtasks.

Bechtel has created a number of supplier alliances, not only for major equipment manufacture and fabrication, but also for bulk materials. In addition to reducing the price of equipment, these alliances also shorten the engineering and procurement cycle resulting in a shorter overall project schedule and reduced EPC costs. Shorter schedules and reduced EPC costs translate into faster payback and increased profitability. These ideas also were be applied to optimize the designs.

Table 2 lists some of the major design improvements and changes that resulted from the application of the above Value Improving Practices to the non-optimized Subtask 1.2 Petroleum Coke IGCC Coproduction Plant design to generate the optimized Subtask 1.3 design.

The Optimized Petroleum Coke IGCC Plant Design

The base case design for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant was developed based on the non-optimized design of the Subtask 1.2 plant. This plant also is located on the U. S. Gulf Coast adjacent to a petroleum refinery. In addition to the VIP items listed in Table 2, the following additional design changes were made for the optimized plant.

1. Newer GE 7FA+e combustion turbines with a higher capacity of 210 MW each and a higher thermal efficiency with lower NOx and CO emissions replaced the GE 7FA gas turbines.
2. The low Btu fuel gas is no longer exported to the refinery, but instead is used within the plant to make high pressure steam which is used to make additional electric power.
3. Redundant equipment was removed unless it was shown to be economically advantageous to retain the extra equipment for increased reliability.
4. The hydrogen plant was redesigned to be more efficient with improved heat recovery.
5. The number of gasification trains was reduced to 2 from 3, and a spare gasifier vessel was added to each train.

The major processing areas and major interconnecting streams for the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant are the same as those shown in Figure 3 for the non-optimized Subtask 1.2 plant. Figure 5 is a train diagram of the optimized plant showing the replication of the major plant sections. Table 3 summarizes the Subtask 1.3 major plant input and output streams and compares them

[7] *Powerline* is a registered trademark of the Bechtel Corporation.

with those of the non-optimized plant. The optimized plant consumes 5,399 TPD of dry petroleum coke (about 3% more than the non-optimized plant) while using about the same size Air Separation Unit and produces 570 MW of gross power; 420 MW from the two combustion turbines and 150 MW from the steam turbine. It exports 461.5 MW of net electric power (about 17% more than the non-optimized plant) while producing the same amount of hydrogen and steam. The increased export power production is attributable to a more efficient design, to higher performance equipment, and to the internal use of the low Btu fuel gas to make additional high pressure steam.

Compared to the non-optimized plant design, the amount of redundant equipment has been significantly reduced.

- The slurry preparation area has been reduced to two 50% trains with two 60% rod mills compared to the non-optimized case which has two 100% trains.
- The gasification, HTHR (high temperature heat removal), and particulate removal (wet scrubbing) contains two 50% gasification trains each with a spare gasifier vessel compared to three complete 50% trains.
- The three 50% trains in the low temperature heat removal (LTHR), acid gas removal (AGR), and sour water treatment areas have been reduced to two 50% trains for the LTHR and AGR areas, and a single 100% sour water treatment area.
- The CO shift and PSA (hydrogen production area) contains two 50% trains compared to three in the non-optimized plant.
- The hydrogen compression area still contains three 50% hydrogen compressors because of their relatively high maintenance requirements.
- The three 50% trains in the sulfur recovery unit (SRU), hydrogenation, and tail gas recycle area have been reduced to two 50% trains for the optimized plant.
- Minor reductions of replicated and unnecessary equipment were made in other areas not mentioned above.

During the Value Improving Practices procedures, Process Availability Modeling studies suggested that a couple of alternate cases could be better than this base case depending upon the costs of replicating the gasification train and/or the gasification reactor vessels. Therefore, this case is designated as the base case, and two alternate cases were developed. These alternate cases will be discussed subsequently.

As a result of the Value Improving Practices effort, significant changes were made in the gasification area while developing the Subtask 1.3 optimized plant design from the Subtask 1.2 non-optimized plant design. In the Subtask 1.2 design, there are three identical and parallel gasification trains with each train having a single gasification reactor vessel. Only two trains will be operating at any one time with the third train acting as a spare. When maintenance work is required on an operating train, such as every other year when refractory replacement is required, it is shut down for repairs, and the spare train is placed on-line. When the repairs are completed, that train now becomes the spare train.

In the Subtask 1.3 optimized design, there are only two identical and parallel gasification trains, but each train contains a spare gasifier vessel that is not connected to the operating section. When it is necessary to replace the refractory in a gasifier, the train is shut down, and piping is rearranged to place the spare vessel in service and completely disconnect the previously operating vessel from the operating areas of the plant. The piping change-out time is expected to require about two weeks. Simultaneously, the normal outage maintenance is performed. When completed, the train is started up with the previously spare gasifier vessel in service. Since the gasifier requiring service now is completely isolated from the operating section, scheduled refractory replacement in the idle gasifier can be performed while the plant is operating at full capacity.

Because of various improvements incorporated the Subtask 1.3 design, less scheduled maintenance is required than at the Wabash River facility, and the scheduled outage periods can be shortened from twenty days to two weeks. Thus, the expected annual maintenance per train consists of only two two-week periods, or only four weeks per year.

Another change implemented in the optimization process was the use of full slurry quench in the gasifer second stage rather than using recycled syngas. This change improves the gasifier efficiency because it utilizes the heat in the syngas to promote the gasification reactions and saves the power needed to recycle the syngas.

Other significant design changes from the Subtask 1.2 design involve the syngas processing. In Subtask 1.2, the hot syngas leaving the gasifier goes to a hot residence vessel to allow further reaction. Following this, it is cooled in the high temperature heat recovery (HTHR) section, and dry char filters remove particulates. A wet scrubbing column downstream of the dry char filters removes chlorides. In Subtask 1.3, the post reactor residence vessel has been eliminated, and the hot syngas goes directly to the HTHR section. Most of the particulates (98+%) are removed from the syngas by a hot gas cyclone. The remaining particulates and chlorides, as well, are removed simultaneously by wet scrubbing with water. The particulates are concentrated and recovered from the wash water by a filter system before being recycled to the gasifier for further reaction. Filtered water is recycled to the wet scrubber or is sent to the sour water stripper.

Emissions performance of the non-optimized and Optimized Petroleum Coke IGCC Coproduction plants are similar as shown in Table 4. The reduced NOx and CO emissions of the optimized plant are the result of diluent injection and replacing the GE 7FA combustion turbine with the newer GE 7FA+e gas turbine which has both a higher power output and a higher thermal efficiency.

The mid-year 2000 installed cost of the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plan is 764.0 MM$, about 23% less than the non-optimized plant. Although both the Subtask 1.2 and Subtask 1.3 plant costs are mid-year 2000 costs, the Subtask 1.3 costs are more reflective of current market pricing. For the Subtask 1.3 plant, current vendor quotes were obtained for most of the added and high cost equipment. Power block costs are based on the actual costs of a similar power project, reflecting current market conditions. Because of the current demand for combustion turbines, the cost of the two turbines appears high compared to historical data.

If the three-train Subtask 1.2 plant were to be built using the Subtask 1.3 optimized gasification train design, that plant would cost about 880 MM$. This is a savings of 113 MM$ or just over 11%, essentially all of which is in the gasification and balance of plant areas.

Subtask 1.3 Minimum Cost Plant

To further reduce the cost of the Optimized Petroleum Coke IGCC Coproduction Plant a minimum cost plant design was developed. Figure 6 is a train diagram showing the replication of various plant sections in the Subtask 1.3 Minimum Cost Plant. In this design, the spare gasifier vessel was removed from each of the two parallel gasification trains resulting in only one gasifier per train; the same number as in Subtask 1.2. As is the case with the Subtask 1.2 plant, each train will require a twelve week outage every other year for refractory replacement.

Because the only change between this case and the Subtask 1.3 Base Case (described in the previous section) is the elimination of the spare gasifier, the input and output stream flow rates and emissions performance will be the same as that for the Subtask 1.3 Base Case. However, because of lower availability, the annual power sales, the annual hydrogen, steam, and sulfur productions rates, and the annual coke consumption will be lower.

The Subtask 1.3 Minimum Cost Plant costs 746 MM$. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which is 18 MM$ less. This difference represents the total installed cost of the two spare gasifiers, one in each train. Thus, the minimum cost case is 18 MM$ less than the optimized Optimized Petroleum Coke IGCC Coproduction Plant base case.

Subtask 1.3 Spare Gasification Train Plant Description

To increase the availability of the Optimized Petroleum Coke IGCC Coproduction Plant, a plant design was developed in which there is a spare gasification train containing all the equipment from the slurry feed preparation through the particulate removal areas. Each train has only one gasifier vessel as is the situation in Subtask 1.2 and in the Subtask 1.3 Minimum Cost case. Figure 7 is a train diagram showing the replication of various plant sections in the Subtask 1.3 Spare Gasification Train Plant. In this design, there are three identical and parallel trains containing the slurry feed tanks and pumps, gasifier, high temperature heat recovery unit (HTRU), and the dry/wet particulate removal system. Each train has a design capacity of 50% of the total plant capacity. This is the same gasifier design that is used in Subtask 1.2. Whenever one train has to be shut down for maintenance, the spare train will be placed in service. Once that train is repaired, it becomes the standby spare train until needed. Therefore, the expected annual maintenance requirements for the gasification area are about the same as the Subtask 1.2 plant. There is insufficient downstream processing capacity to allow for the simultaneous operation of all three gasification trains.

The only change between this case and the Minimum Cost Case (described in the previous sections) is the addition of the spare gasification train. Thus, the input and output stream flow rates and emissions performance of this option will be the same as those of the Subtask 1.3 Base Case. However, because of the higher availability, the annual power sales, annual hydrogen, steam and sulfur productions, and annual coke consumption will be higher.

The cost of the Subtask 1.3 Spare Gasification Train Plant is 812.6 MM$. The cost for all plant sections are the same as the Subtask 1.3 Base Case except for the gasification area which costs 48.5 MM$ more. This difference represents the net difference in total installed cost of the spare gasification train and the removal of the two spare gasifiers from the Base Case design. Thus, the Spare Gasification train case costs 48.5 MM$ more than the Subtask 1.3 Optimized Petroleum Coke IGCC Coproduction Plant Base Case. The Spare Gasification train case costs 66.5 MM$ more than the Minimum Cost case

Use of Backup Natural Gas

The gasification trains of the Subtask 1.2 plant and all three Subtask 1.3 plants are sized so that one train has sufficient capacity to provide the design amounts of hydrogen and steam to the adjacent petroleum refinery. However, when only one gasification train is operating, there is insufficient syngas available to meet the hydrogen demand and fully fire one combustion turbine. Thus, in this situation, about 63.8 MMscfd of backup natural gas will be used to supplement the syngas and co-fire both combustion turbines. When this situation occurs, the power output from the combustion turbines is reduced. However, the internal power consumption within the plant also is reduced by the amount of power consumed by the idle gasification train and air separation unit. The net effect of this combination of events is that there is a net reduction in the export power.

In the less frequent situation where only one syngas train is operating and only one combustion turbine is available, backup natural gas also will be used to load the available gas turbine and supply the design hydrogen and steam demands. In this situation, the export power produced by the plant is slightly less than half the design rate.

In the least likely situation where both gasification trains are not available and only one combustion turbine is available, natural gas will be used to fire that turbine to produce only export power. No export steam or hydrogen will be produced.

Availability Analysis

In Table 5.0A of the Final Report for the Wabash River Wabash River Repowering Project, Global Energy reported downtime and an availability analysis of each plant system for the final year of the Demonstration Period.[5] During this March 1, 1998 through February 28, 1999 period, the plant was operating on coal for 62.37% of the time. There were three scheduled outages for 11.67% of the time (three periods totaling 42 days), and non-scheduled outages accounted for the remaining 25.96% of the time (95 days).

After adjustments, this data was used to estimate the availability of the Subtask 1.2 and Subtask 1.3 Petroleum Coke IGCC Coproduction Plant designs. Using the EPRI recommended procedure, availability estimates were calculated for the Subtask 1.2 non-optimized Petroleum Coke IGCC Coproduction Plant and for the three Subtask 1.3 optimized plant designs.[8]

Table 5 compares the design (stream day) and average daily (calendar day) feed and product rates for the non-optimized Subtask 1.2 case and the three Subtask 1.3 cases. As the table shows there are significant differences between the calendar day rates and the stream day rates for the power, sulfur, slag, and fuel gas products, and for the coke and flux feeds. This is because these design rates are based on two trains running simultaneously. The calendar day rates are closest to the design rates for the two cases with three gasification trains because only two of them need to be running simultaneously to make the design rates. For all cases, the calendar day steam and hydrogen rates are a lot closer to the design rates since only one gasification train has to be operating for the plant to produce the design product rates.

The daily average natural gas consumptions shown in Table 5 are the lowest for the two cases with three parallel gasification trains. This is because these cases have the highest availability of two trains. Thus, they, require the least amount of backup natural gas firing. The availability of the gasification trains in the Subtask 1.3 Base Case is higher than in the Subtask 1.3 Minimum Cost case because the former has a spare gasification reactor in each train. Consequently, the Base Case requires less natural gas usage than the Minimum Cost case.

Figure 8 compares the design and daily average coke consumptions for the plants. In all cases, the average daily coke consumption is significantly less than the design capacity. This difference is the least for the Subtask 1.3 Spare Gasification Train Case where it is only 585 TPD of dry coke less than the design capacity of 5,399 TPD, and it is the greatest for the Subtask 1.3 Minimum Cost Case where it is

[8] Research Report AP-4216, *Availability Analysis Handbook for Coal Gasification and Combustion Turbine-based Power Systems,* Research Project 1800-1, Electric Power Research Institute, 3412 Hillview Avenue, Palo Alto, CA, 94304, August 1985.

1,426 TPD less. For the Subtask 1.3 Base Case, the average daily dry coke consumption is 1,090 TPD less than the design rate of 5,399 TPD.

Figure 9 shows the amount of time that the various plant sections are operating. For Subtask 1.2,

- two gasification trains and two combustion turbines (code: 2Gs & 2 CTs) are operating about 77.4% of the time;
- only 1 gasification train and 2 combustion turbines (code: 1 G & 2 CTs) are operating about 13.4% of the time;
- only 1 gasification train and 1 combustion turbine (code: 1 G & 1 CT) are operating about 8.4% of the time; and
- only 1 combustion turbine (Code: 0Gs & 1CT) are operating about 0.6% of the time.

Thus, for the Subtask 1.2 plant, one or more gas turbines are using natural gas as a backup fuel for about 22.4% of the time because an insufficient amount of syngas is available. The equivalent syngas availability is 88.3%, and the equivalent hydrogen and steam availability is 99.2%.

For the Subtask 1.3 Base Case, backup gas firing is used almost 38% of the time. The equivalent syngas availability is 79.8%, the equivalent hydrogen availability is 96.8 and the equivalent steam availability is 97.8%.

For the Subtask 1.3 Minimum Cost case, backup gas firing is used about 49.2% of the time. The equivalent syngas availability is 73.6%, the equivalent hydrogen availability is 96.6% and the equivalent steam availability is 95.6%.

The Subtask 1.3 Spare Gasification Train case uses backup natural gas firing for about 20.9% of the time because the individual gasification trains have the highest availability. The equivalent syngas availability is 89.2%, the equivalent hydrogen availability is 98.4%, and the equivalent steam availability is 99.4%.

Although not discernable in the figure, all four bars have the same height of 99.8%, which is the availability of one of the two combustion turbines.

Figure 10 shows the equivalent power availability using backup natural gas as a function of the design rate produced by each mode of operation for the four cases. The height of each bar represents the annual equivalent power availability of each case. The Subtask 1.3 Spare Gasification Train Case has the highest total equivalent power availability of 94.7%, and the Subtask 1.3 Minimum Cost Case has the lowest equivalent power availability of 92.4%. For the Subtask 1.3 Base Case, about 31.5% of the design power is made when some natural gas is being used either to supplement or replace the syngas, and for the Subtask 1.3 Spare Gasification Train Case, only about 15.8% of the power is being made when some natural gas is being used.

Discounted Cash Flow Financial Analysis

The financial analysis was performed using a discounted cash flow (DCF) model that was developed by Nexant Inc. (formerly Bechtel Technology and Consulting) for the DOE as part of the Integrated Gasification Combined Cycle (IGCC) Economic and Capital Budgeting Practices Task.[9] This model calculates investment decision criteria used by industrial end-users and project developers to evaluate the economic feasibility of IGCC projects. The IGCC financial model consists of 18 coupled spreadsheets in

[9] Nexant Inc., "Financial Model Users Guide – IGCC Economic and Capital Budgeting Evaluation", Report for the U. S. Department of Energy, Contract No. DE-AM01-98FE64778, May 2000.

a Microsoft Excel workbook format. The model spreadsheets are organized into four main sections; (1) data input sheets, (2) supporting analysis sheets, (3) financial statements, and (4) project summary results sheets.

Table 6 shows the required power selling price that will produce an after-tax return on investment (ROI) of 12%. (The other basic economic parameters are shown in the middle column of Table 7.) The Subtask 1.3 Spare Gasification Train Case has the lowest required selling price of 32.48 $/MW-hr (or 3.248 cents/kW-hr). The Subtask 1.3 Base Case has the next lowest required power selling price of 34.45 $/MW-hr followed by the Subtask 1.3 Minimum Cost case that has a required power selling price of 36.49 $/MW-hr. These three cases are a significant improvement over the Subtask 1.2 case which has a required power selling price of 43.36 $/MW-hr to produce a 12% after-tax ROI. Thus, the Subtask 1.3 Spare Gasification Train Case lowered the required power selling price by almost 11 $/MW-hr (or 1.1 cents/kW-hr), a 25% reduction.

Based on these results, the Subtask 1.3 Spare Gasification Train Case is the preferred Subtask 1.3 case because it has the highest return on investment and lowest required power selling price for a 12% after tax ROI even though it has the highest EPC cost.

Table 7 shows the sensitivity of some individual component prices and financial parameters for the Subtask 1.3 Base Case starting from a 12% ROI (with a power price of 34.45 $/MW-hr). Each item was varied individually without affecting any other item. The sensitivities of the other Subtask 1.3 cases will be similar. Most sensitivities are based on a $\pm$10% change from the base value except when a larger change is used because it either makes more sense or it is needed to show a meaningful result. The power selling price is the most significant product price with a 10% increase resulting in a 3.27% increase in the ROI, and a 10% decrease resulting in a 3.40% decrease in the ROI. Hydrogen was the second most significant product price with a +10% increase resulting in a 1.07% increase in the ROI, and a 10% decrease resulting in a 1.08% decrease in the ROI. Steam was the next most significant with a +10% change resulting in a +0.69% increase in the ROI, and a –10% change resulting in a 0.70% decrease in the ROI. Changes in the sulfur and slag prices have only a small influence on the ROI.

A change in the coke price of 5 $/ton from the base coke price of 0 will change the ROI by +1.78% with an increase in the coke price decreasing the ROI and vice-versa. A change in the natural gas price of +10% (or +0.26 $/MMBtu) will change the ROI by +0.60% with an increase in the gas price causing a decrease in the ROI and vice-versa. The ROI essentially is insensitive to the flux price with a 100% change from the base price of 5 $/ton only causing the ROI to change by 0.04%.

The interest rate is the most sensitive of the financial parameters that were studied. A 20% decrease in the loan interest rate to 8% from the base interest rate of 10% will increase the ROI to 15.75% from 12.00%, and a 20% increase in the interest rate to 12% will lower the ROI to 8.20%. A 20% decrease in the loan amount from 80% to 72% will lower the ROI by 0.57% to 11.43%, and a 20% increase in the loan amount to 88% will increase the ROI by 0.96 to 12.96%. Decreasing the income tax rate by 10% from 40% to 36% will increase the ROI to 12.48%, and a 10% increase in the tax rate to 44% will lower the ROI by 0.52% to 11.48%.

Figure 11 shows the effect of only the power selling price on the after-tax ROI. As expected, the ROI is a strong function of the power price. The Subtask 1.3 ROIs are significantly better than those for Subtask 1.2 reflecting the effects of both the lower costs and higher gasification train availabilities of the Subtask 1.3 cases. The larger slopes of the Subtask 1.3 ROIs are a result of the lower capital costs of the Subtask 1.3 cases compared to the Subtask 1.2 case. As seen from the figure, the Subtask 1.3 Spare

Gasification Train Case must have a required electric power selling price of about 35.8 $/MW-hr for a 15% after-tax ROI.

The solid points in Figure 11 are based on an 80% loan at a 10% interest rate and a 3% financing fee. The open points are based on a 8% loan interest rate and the same 3% financing fee. Reducing the loan interest rate increases the after-tax ROI by about 3.7%. At a 30 $/MW-hr power price, the ROI for the preferred Subtask 1.3 Spare Gasification Train Case increases to about 13.4%, and that for the Base Case increases to 11.3%.

Figure 12 shows the combined effect of changes in the natural gas price, steam, hydrogen, low Btu fuel gas, and power prices on the ROI for the four cases as a function of the product price index. Table 8 shows the relationship between product price index and the five commodity prices.

With a 10% increase in the product price index, the natural gas price increases to 2.86 $/MMBtu, and the Subtask 1.3 Spare Gasification Train Case has an ROI of about 12.1%. At a gas price of 3.13 $/MMBtu corresponding to a 1.2 product price index, the Spare Gasification Train Case has an ROI of about 16.6%. At the 1.2 price index, the Subtask 1.3 Base Case has an ROI of 14.5%.

The above economic analysis suggests that for situations where export power can be sold at attractive prices during the entire year, the Spare Gasification Train Case is the preferred case, since this case has the highest ROI. Although the most expensive case, on an annual basis, this case consumes the largest amount of coke per dollar of plant cost. It also is the most attractive case when coke storage facilities are limited and an alternate disposal means may be unattractive. This case also is the most attractive when outages in the steam and hydrogen supply will incur large penalties. In such a situation, additional redundancy in the hydrogen production facilities may be justified.

The Minimum Cost Case may be the most attractive in the situation where power prices are low in the spring and fall and long outages can be tolerated. This case has the lowest ROI. Although the least expensive case, on an annual basis, this case consumes the least amount of coke per dollar of plant cost. This case may be the most attractive when coke storage or alternate coke disposal means are available during outages. In the situation where a refinery expansion which will increase coke production is anticipated, the Minimum Cost Case may be preferred because it can be later expanded to either the Base Case or the Spare Gasification Train Case.

The Base Case may be the most attractive case when power prices are low in the spring and fall, but still reasonably attractive, and scheduled outages can be taken at these times. This case also may be the preferred case when the penalties associated with outages in the refinery steam and hydrogen supplies are not very large or alternate, but more expensive sources, are available.

Current Market Pricing

Currently, the United States is in a period of low inflation, and as a result, interest rates are low. Table 9 shows the effect of reducing the loan interest rate from 10% to a current market value of 8% while still maintaining the same 3% upfront financing charge. The first line shows the required power selling prices for a 12% ROI. Compared to the previous results shown in Table 6, the required power prices for the Subtask 1.3 cases have dropped by 2.7 - 5.8 $/MW-hr. The Subtask 1.3 Spare Gasification Train Case now requires a power selling price of 28.56 $/MW-hr for a 12% ROI. This price is very competitive when compared to the minimum price for cogeneration power in Texas.

Presently, there are wide variations in the future projections of the natural gas price. At the present time, a 3.00 $/MMBtu price for natural gas seems to be a reasonable value for economic projections. The bottom line shows the ROI when all the product prices are indexed to a 3.00 $/MMBtu natural gas price. This corresponds to a power price to 31.15 $/MW-hr. In this scenario, the ROIs have increased by another 3 to 4%. The Subtask 1.3 Spare Gasification Train Case now has an ROI of 18.15%. Based on these prices, an optimized coke fueled IGCC plant, such as that developed in this study, is poised to enter the power market.

Additionally, based on extensive review of the Wabash River operating experience over the past two years with the dry char particulate filters and additional analysis of a cyclone plus dry filter system, Global Energy is confident that the both the cost and reliability of the a dry particulate removal system can be significantly reduced. This advanced system would replace the cyclone / wet scrubbing system used in this study. Recent operating experience on petroleum coke indicates that this dry filter system will have near 100% availability without any increase in scheduled outage. For the preferred Spare Gasification Train Case, employing this advanced dry particulate removal system can increase the plant ROI by an additional 1.5%, thereby making dry particulate removal the preferred system for the next plant.

Summary

Global Energy's process engineering, plant design and operation experience coupled with Bechtel's design template approach and Value Improving Practices (VIP) procedures were employed to develop three optimized designs for petroleum coke IGCC coproduction plants. The most attractive of these designs is the one that contains a spare gasification train, and under a current day economic scenario, it appears economically viable.

Based on an optimized design for a future plant currently under development in Subtask 1.4, there are several opportunities for further cost reductions, such as:

- ◊ Economy of scale from increased combustion turbine capacity (and efficiency) from the use of a "H class" design
- ◊ Simplified gasification reactor design at higher pressure
- ◊ Implementation of slurry feed vaporization for increased efficiency
- ◊ Simplified heat recovery
- ◊ Simplified water treatment and zero liquid discharge of process water
- ◊ Further particulate filter advancements (such as metal to ceramics)
- ◊ Warm gas cleanup

The above enhancements are possible in the near future and will clearly benefit both coke and coal fueled IGCC technology thereby making coal based IGCC plants a clear leader in clean coal power technology.

File: GTC Paper 10-01d.doc
8/27/01

Table 1
Plant Design and Operating Conditions

	Subtask 1.1 Wabash River Greenfield Project Plant		Subtask 1.2 Petroleum Coke IGCC Coproduction Plant	
Location	Typical Mid-Western State		U.S. Gulf Coast near a Petroleum Refinery	
Feedstock	Illinois No. 6 Coal		Green Delayed Petroleum Coke	
	Dry Basis	As Rec'd	Dry Basis	As Rec'd
HHV, Btu/lb	12,749	10,900	14,848	13,810
Analysis, wt %				
Carbon	69.9	59.76	88.76	82.55
Hydrogen	5.0	4.28	3.20	2.98
Nitrogen	1.3	1.11	0.90	0.84
Sulfur	2.58	2.21	7.00	6.51
Oxygen	8.27	7.07	-	-
Chlorine	0.13	0.11	50 ppm	47 ppm
V & Ni	-	-	1900 ppm	1767 ppm
Ash	12.7	10.86	0.14	0.13
Moisture	-	14.5	-	6.99
Total	100	100	100	100
Inputs				
Fuel, dry basis	2,260 tons/day		5,250 tons/day	
Makeup Water,	2,280 gpm		4,830 gpm	
Refinery Condensate	0		686,000 lb/hr	
Outputs				
Export Power, MW	269.3		396	
Slag, tons/day	356		190	
Sulfur, tons/day	57		367	
Hydrogen	0		79.4 MMscfd	
Purity	-		99 %	
Pressure	-		1000 psig	
Temperature	-		120^{o}F	
Steam	0		980,000 lb/hr	
Pressure	-		700 psig	
Temperature	-		750^{o}F	
Waste Water	120 gpm		30 gpm	
Gas Emissions				
Particulates	Nil		Nil	
SOx, as SO_2	96.8% Removal		99.5 % Removal	
	312 lb/hr		306 lb/hr	
	42 ppmvd		20 ppmvd	
NOx, as NO_2	161 lb/hr		325 lb/hr	
	30 ppmvd		30 ppmvd	
CO	56 lb/hr		111 lb/hr	
	17 ppmvd		17 ppmvd	

Table 2

Subtask 1.3 Major VIP and Optimization Items

Plant **Section**	<u>Description</u>
100	Simplified the solids handling system
150	Removed the slurry feed heaters and spare pumps
300	• Maximized the use of slurry quench in the gasifier second stage • Maximized syngas moisturization • Used a cyclone and wet particulate removal system rather than dry char filters to clean the syngas • Improved the burner design • Removed the post reactor residence vessel
400/420	Simplified the Claus plant, amine, and sour water stripper resulting in lower incinerator emissions
500	• Used a state-of-the-art GE 7FA+e gas turbine with 210 MW output and lower NOx • Combined syngas moisturization with use of the least cost diluent (steam) in the gas turbine
General	• Bechtel's Powerline cost and philosophy applied to an IGCC plant; i.e., a building block approach • Bechtel's MPAG (Multi Project Acquisition Group) was used to obtain low equipment and bulk material costs • Availability analysis was used to select design with maximum on-stream time • The COMET plant layout model was used to develop a compact plant layout and minimize amount of high cost and alloy piping. • Design features were added to reduce the O&M costs

Table 3
Design Input and Output Streams for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Plant Input		
Coke Feed, as received, TPD	5,515	5,673
Dry Coke Feed to Gasifiers, TPD	5,249	5,399
Oxygen Production, TPD of 95% O_2	5,962	5,917
Total Fresh Water Consumption, gpm	4,830	5,150
Condensate Return from the Refinery, lb/hr	686,000	686,000
Flux, TPD	107	110.2
Plant Output		
Net Power Output, MW	395.8	461.5
Sulfur, TPD	367	371.8
Slag, TPD (15% moisture)	190	194.5
Hydrogen, MMscfd	79.4	80
HP Steam, 700 psig/750^{o}F, lb/hr	980,000	980,000
Fuel Gas Export, MMscfd	99.6	0
MMBtu/hr, (HHV)	363	0

Table 4
Total Emissions Summary for the Optimized and Non-optimized Petroleum Coke IGCC Coproduction Plants

	Subtask 1.2 Non-optimized Plant	Subtask 1.3 Optimized Plant
Total Exhaust Gas Flow Rate, lb/hr (see note)	7,588,700	8,602,300
Emissions		
SOx ppmvd	20	24
SOx as SO_2, lb/hr	306	385
NOx, ppmvd	30	14
NOx as NO_2, lb/hr	325	166
CO, ppmvd	17	15
CO, lb/hr	111	105
CO_2, lb/hr (see note)	1,019,074	1,438,367
VOC and Particulates, lb/hr	NIL	NIL
Opacity	0	0
Sulfur Removal, %	99.5	99.4

Note: The exhaust gas flow rate and CO_2 rate for the Subtask 1.3 optimized plant include burning the low Btu PSA off gas to make high pressure steam, but for the non-optimized Subtask 1.2 plant, the low Btu PSA off gas is sold as fuel gas to the refinery.

Table 5
Design and Daily Average Feed and Product Rates for Subtasks 1.2 and 1.3

	Subtask 1.2		**Subtask 1.3**			
				Daily Average		
Case	Design	Daily Average	Design	Base Case	Minimum Cost Case	Spare Solids
Product Rates						
Power, MW	395.8	374.3	460.7	430.0	425.4	436.4
Steam, Mlb/hr	980.0	972.2	980.0	958.6	946.2	974.1
Hydrogen, MMscfd	79.4	78.8	80.0	77.5	76.5	78.7
Sulfur, TPD	367.0	324.1	371.8	296.8	273.6	331.5
Slag, TPD	190.0	167.8	194.5	155.3	143.1	173.4
Fuel Gas, MMscfd	99.6	98.8	0	0	0	0
Input Rates						
Coke, TPD	5,249	4,635	5,399	4,310	3,973	4,814
Flux, TPD	107	94.5	110.2	88.0	81.1	98.3
Natural Gas, MMBtu/d	0	10,099	0	20,000	26,977	9,303

Table 6
Basic Financial Model Results

	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Gasification Train Case
Required Power Selling Price for a 12% after-tax ROI, $/MW-hr	43.36	34.45	36.49	32.48

Table 7
Sensitivity of Individual Component Prices and Financial Parameters on the Subtask 1.3 Base case Starting from a 12% ROI (with a Power Price of 34.45 $/MW-hr)

	Decrease			Base	Increase		
	ROI	Value	% Change	Value	% Change	Value	ROI
Products							
Power	8.60%	31.00 $/MW-hr	-10%	**34.45 $/MW-hr**	+10%	37.90 $/MW-hr	15.27%
Hydrogen	10.92%	1.17 $/Mscf	-10%	**1.30 $/Mscf**	+10%	1.43 $/Mscf	13.07%
Steam	11.30%	5.04 $/t	-10%	**5.60 $/t**	+10%	6.16 $/t	12.69%
Sulfur	11.93%	27 $/t	-10%	**30 $/t**	+10%	33 $/t	12.07%
Slag	11.94%	-5 $/t	---	**0 $/t**	---	5 $/t	12.06%
Feeds							
Coke	13.75%	-5 $/t	---	**0 $/t**	---	5 $/t	10.25%
Natural Gas	12.60%	2.34 $/MMBtu	-10%	**2.60 $/MMBtu**	+10%	2.86 $/MMBtu	11.39%
Flux	12.04%	0 $/t	100%	**5 $/t**	+100%	10 $/t	11.96%
Financial							
Interest Rate	15.75%	8%	-20%	**10%**	+20%	12%	8.20%
Loan Amount	11.43%	72%	-20%	**80%**	+20%	88%	12.96%
Tax Rate	12.48%	36%	10%	**40%**	+10%	44%	11.48%

Note: Products and Feeds each are listed in decreasing sensitivity.

Table 8
Product Price Index and Commodity Prices

Product Price Index	Natural Gas, $/MMBtu	Power, $/MW	Hydrogen, $/Mscf	Steam, $/ton	Fuel Gas, $/Mscf
1.00	2.60	27.00	1.30	5.60	0.2274
1.05	2.73	28.35	1.43	5.88	0.2388
1.10	2.86	29.70	1.58	6.16	0.2501
1.15	2.99	31.05	1.69	6.44	0.2615
1.20	3.12	32.40	1.82	6.72	0.2729

Table 9
Financial Model Results with an 8% Loan Interest Rate

	Subtask 1.2	Subtask 1.3 Base Case	Subtask 1.3 Minimum Cost Case	Subtask 1.3 Spare Gasification Train Case
Required power selling price for a 12% return on investment	37.52	31.68	32.79	28.56
Return on investment with all prices indexed to 3.00 $/MM Btu Natural Gas	11.55%	15.99%	13.65%	18.15%

Figure 1

Steps for Optimization of the Coal IGCC Design and the Petroleum Coke-IGCC Coproduction Plant

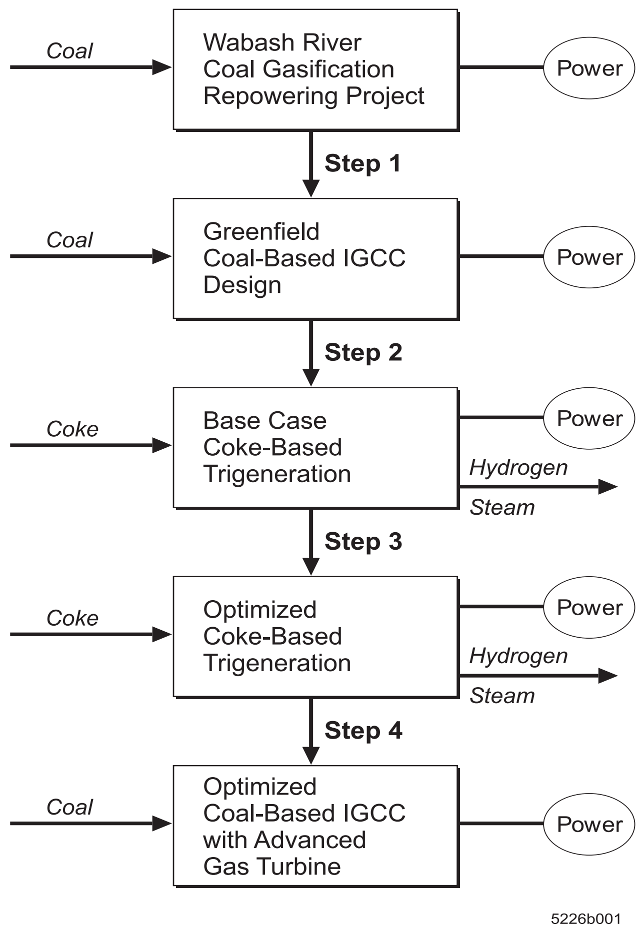
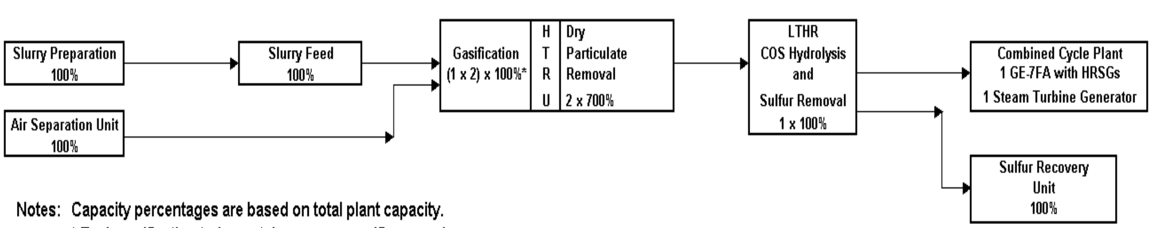


Figure 2

Wabash River Greenfield Plant

Block Flow (Train) Diagram



Notes: Capacity percentages are based on total plant capacity.
* Each gasification train contains a spare gasifier vessel.

Figure 3

Petroleum Coke IGCC Coproduction Plant Simplified Block Flow Diagram

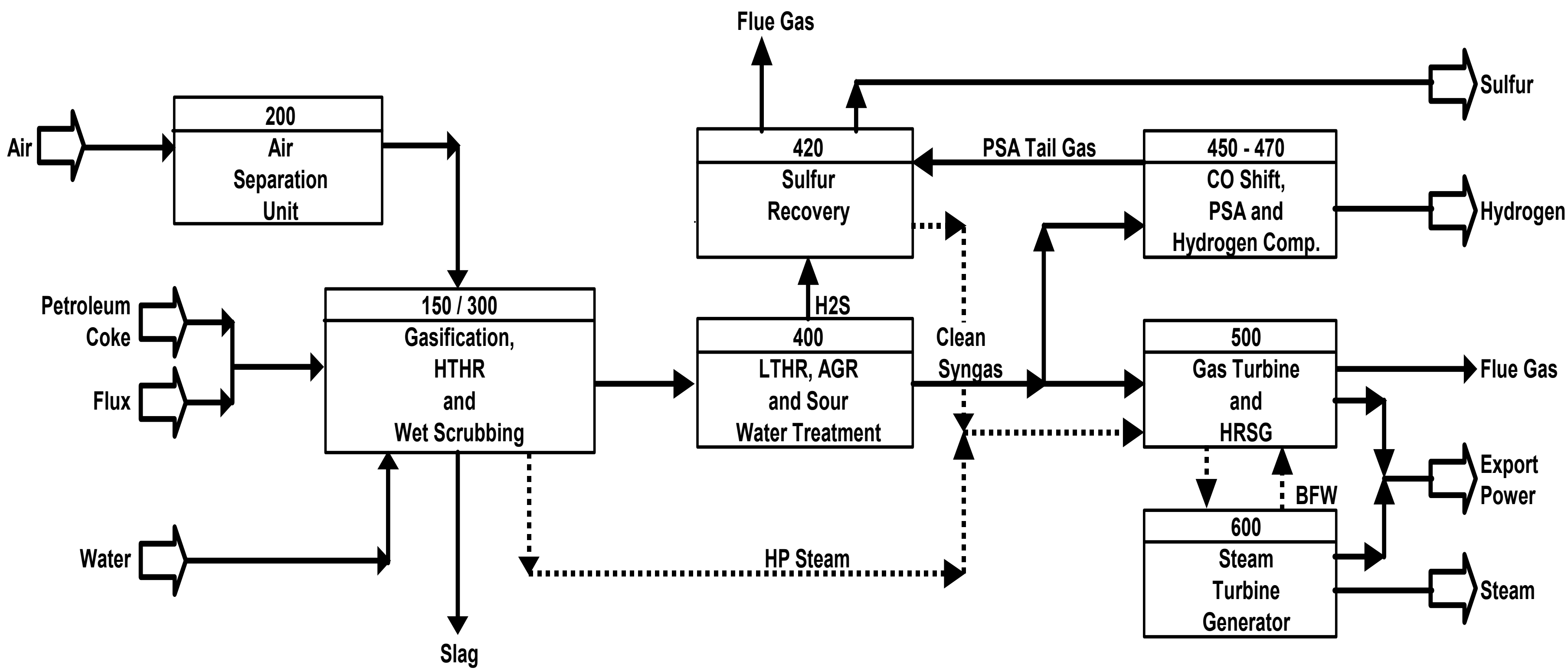
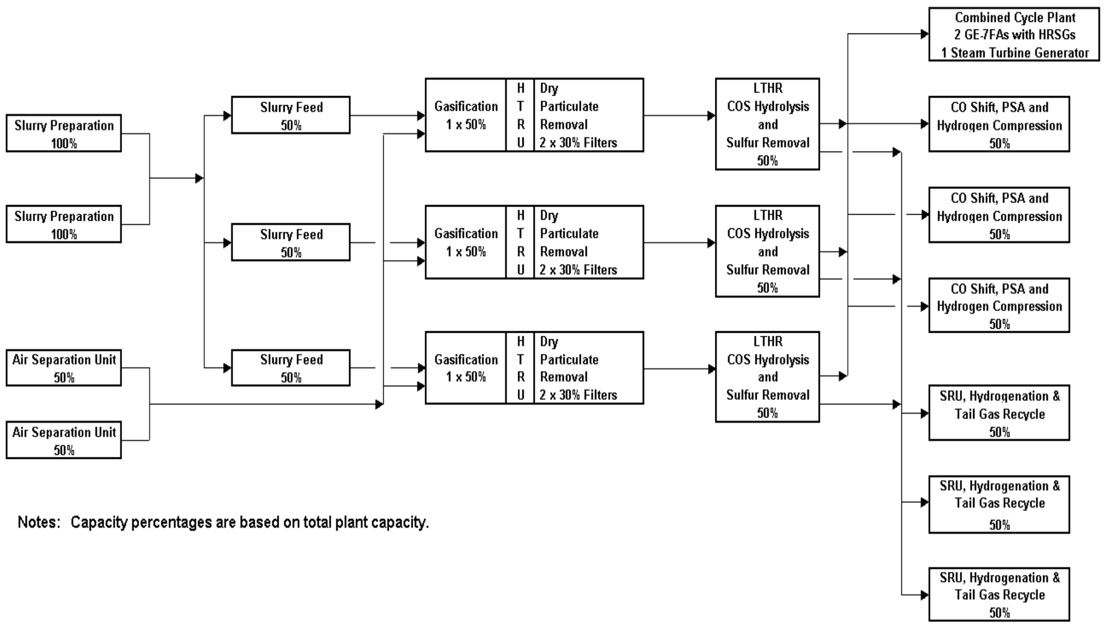


Figure 4

Subtask 1.2 - Block Flow (Train) Diagram

Non-optimized Petroleum Coke IGCC Coproduction Plant

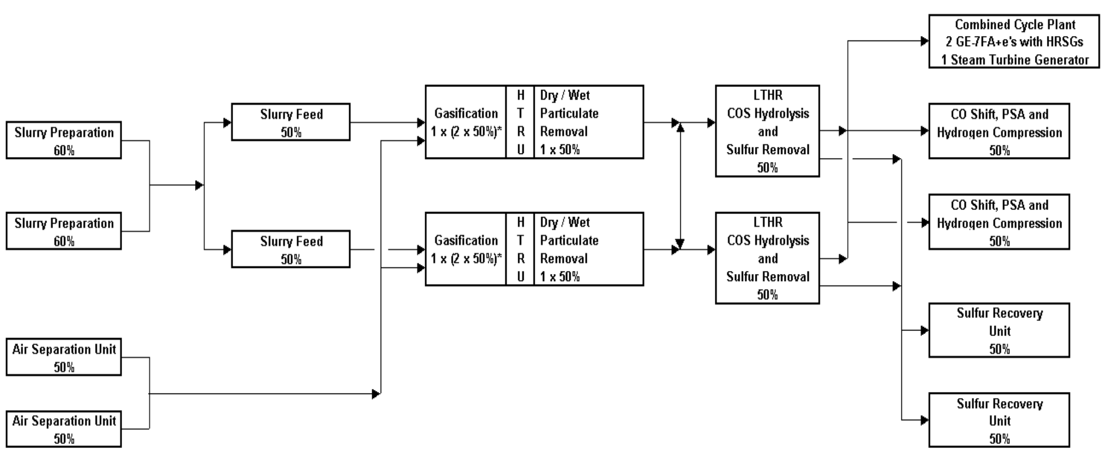


Notes: Capacity percentages are based on total plant capacity.

Figure 5

Subtask 1.3 Base Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

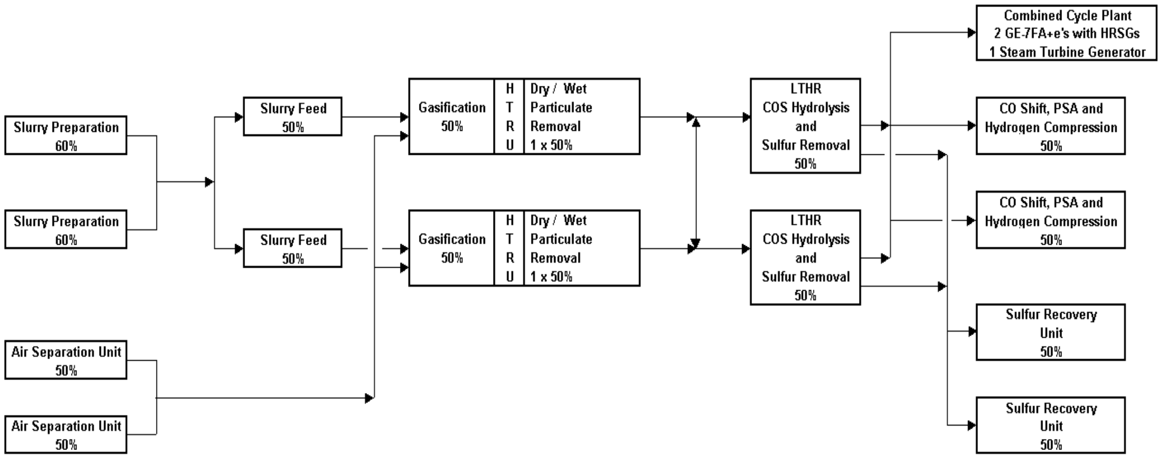


Notes: Capacity percentages are based on total plant capacity.
* Each gasification train contains a spare gasifier vessel.

Figure 6

Subtask 1.3A Minimum Cost Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant

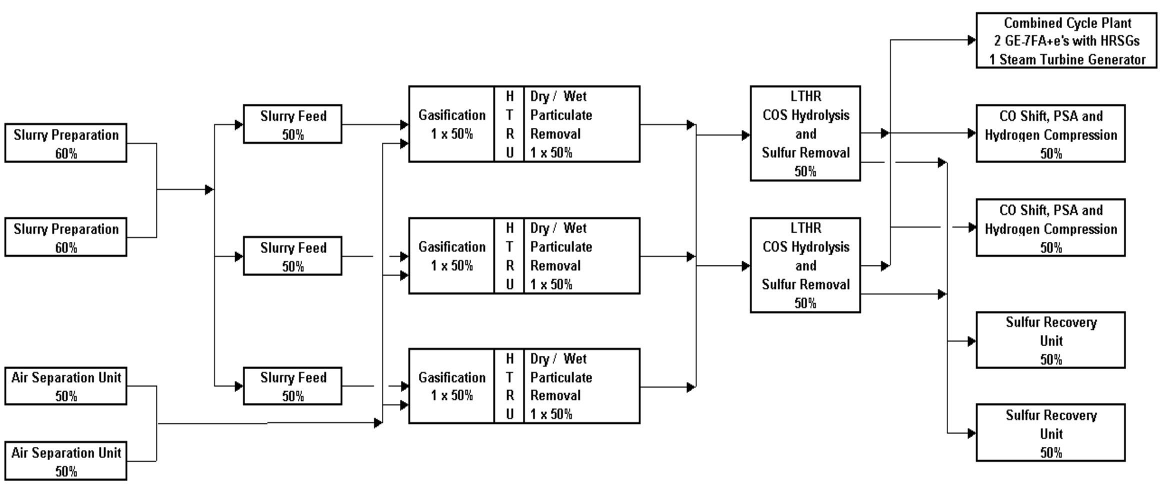


Notes: Capacity percentages are based on total plant capacity.

Figure 7

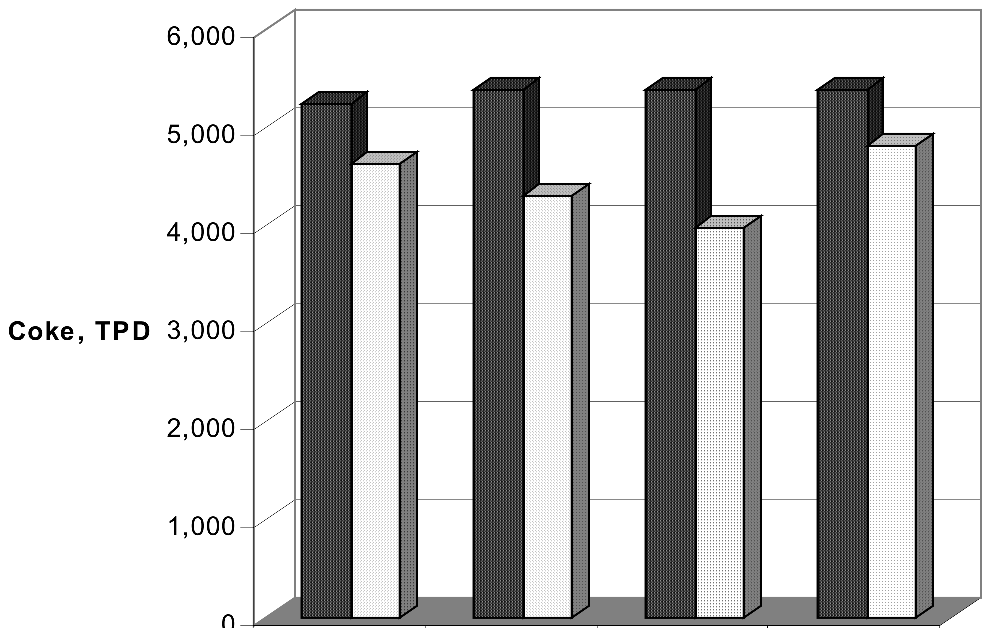
Subtask 1.3S Spare Gasification Train Case - Block Flow (Train) Diagram

Optimized Petroleum Coke IGCC Coproduction Plant



Notes: Capacity percentages are based on total plant capacity.

Figure 8
Design and Daily Average Coke Consumptions



	Subtask 1.2	1.3 Base Case	1.3 Min Cost	1.3 Spare Gasification Train
Design	5,249	5,399	5,399	5,399
Average	4,635	4,310	3,973	4,814

Figure 9
Equipment Availability

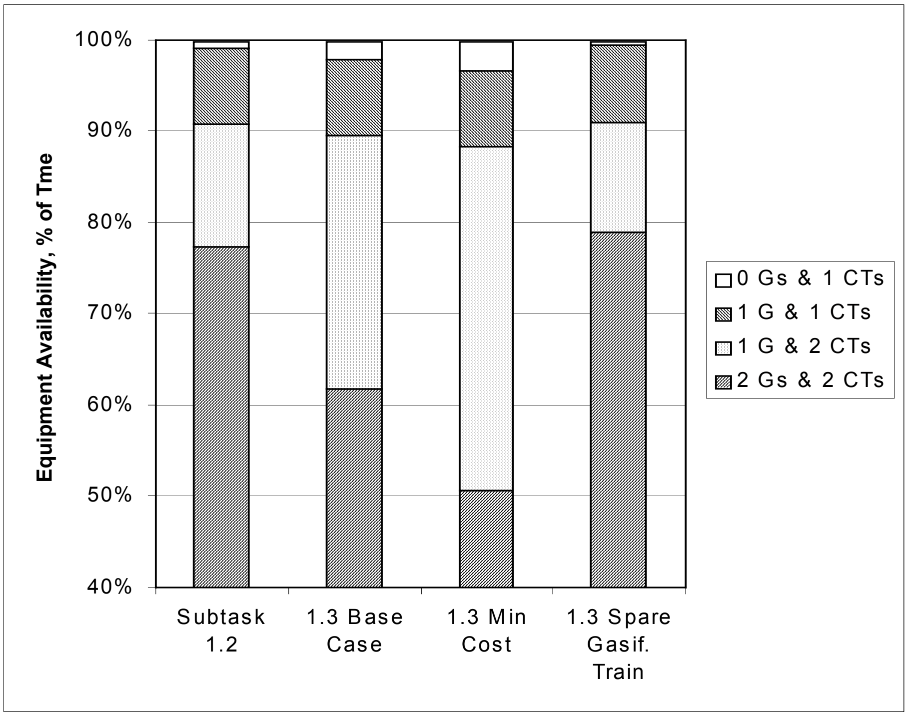


Figure 10
Equivalent Power Availability

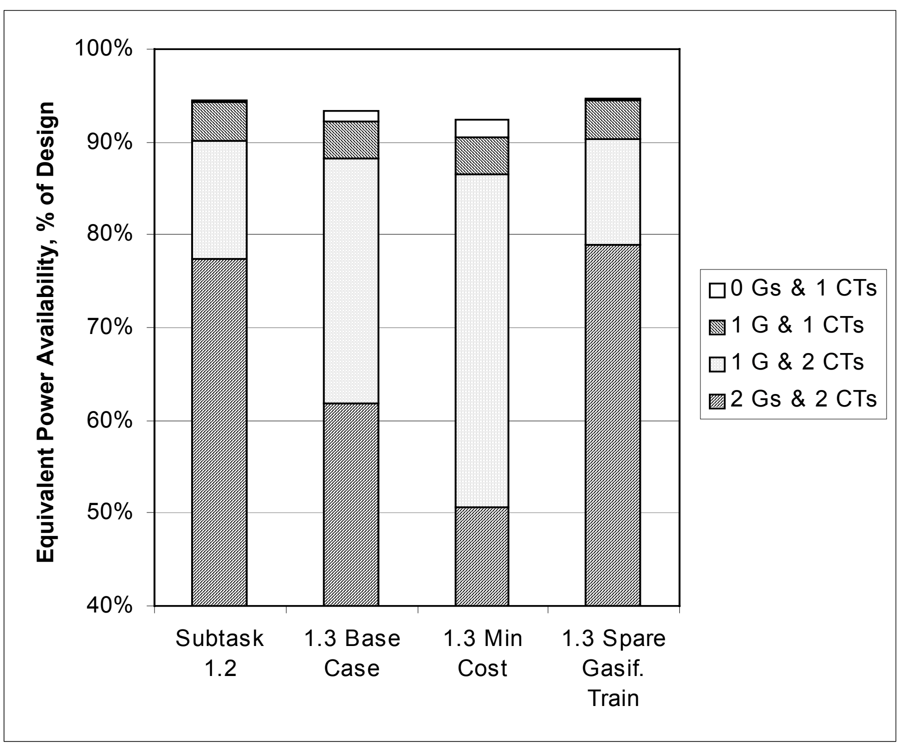


Figure 11
Effect of Power Selling Price on the Return on Investment

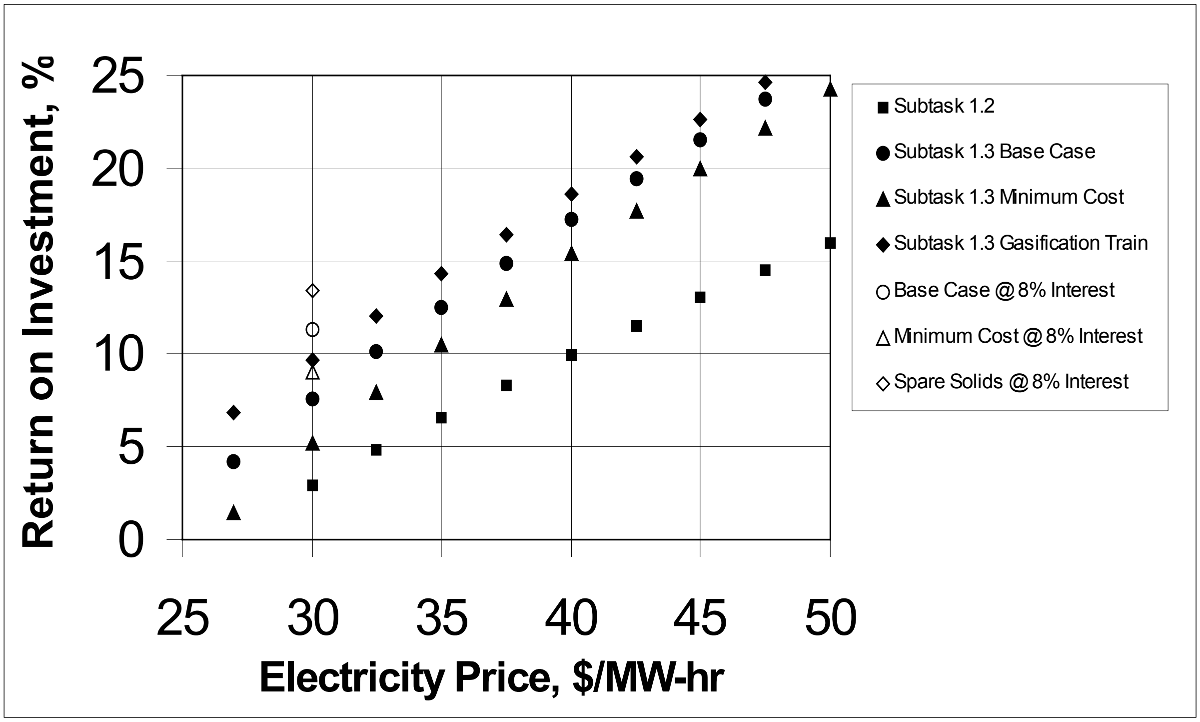
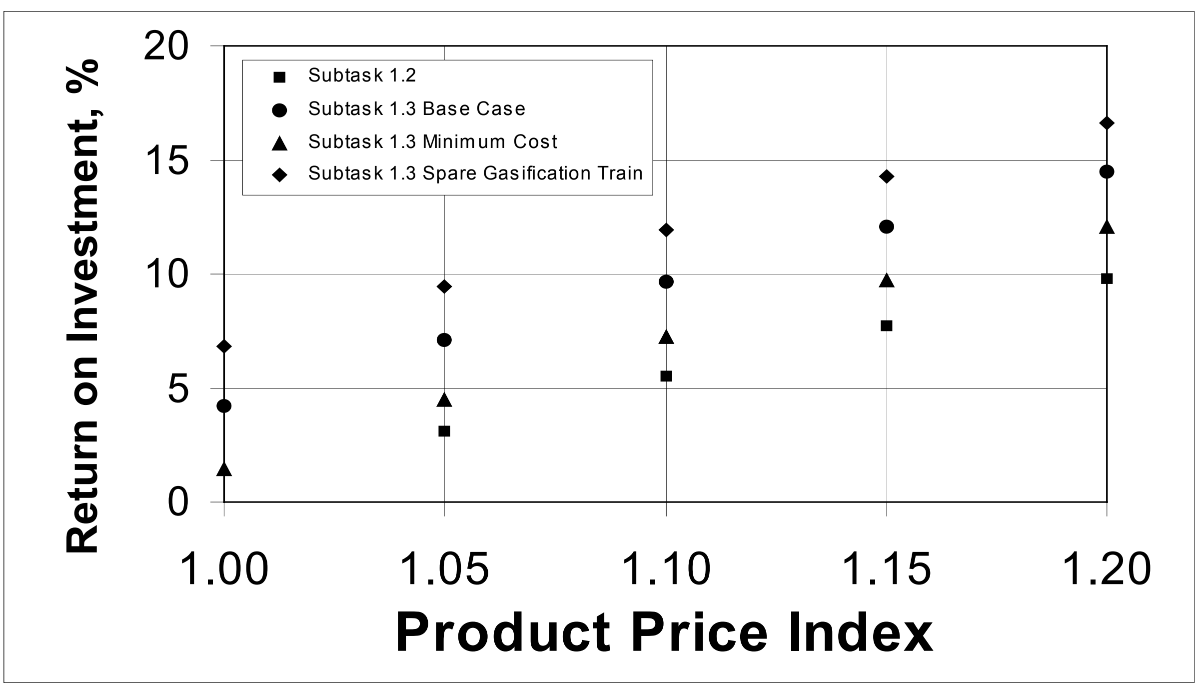


Figure 12
Effect of Natural Gas Price and Associated Product Prices on the Return on Investment



44 Montgomery Street, Suite 4100
San Francisco, CA 94104-4814
tel: +1 415 912 2100
fax: +1 415 981 9744
email: info@nexant.com

www.nexant.com